

**PUBLIC SERVICE COMMISSION  
OF WEST VIRGINIA  
CHARLESTON**

CASE NO. 17-0296-E-PC

MONONGAHELA POWER COMPANY and  
THE POTOMAC EDISON COMPANY,

Petition for Approval of a Generation Resource  
Transaction and Related Relief.

**COMMISSION ORDER**

January 26, 2018

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**APPENDIX A PROCEDURAL HISTORY OF THE CASE.**

**PUBLIC SERVICE COMMISSION  
OF WEST VIRGINIA  
CHARLESTON**

At a session of the PUBLIC SERVICE COMMISSION OF WEST VIRGINIA in the City of Charleston on the 26th day of January 2018.

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**COMMISSION ORDER**

The Commission does not grant the Petition as filed; however, the Commission authorizes Monongahela Power Company (Mon Power) to purchase the 1,300 MW Pleasants Power Station (Pleasants) from its affiliate, Allegheny Energy Supply Company (AE Supply), subject to certain significant conditions. The conditions require limitations on the cost to customers based on the market value of Pleasants capacity and energy, limitations on recovery of closing costs if the plant is retired early, limitation on recovery of all closing costs related to the McElroy's Run Impoundment and Dam, protection against costs related to prior operations of the plant and prior or current operations of the McElroy's Run Impoundment and Dam, all as more fully described in the Order.

**I. INTRODUCTION**

On March 7, 2017, Mon Power and The Potomac Edison Company (PE) (together the Companies) filed a joint petition (Petition) for approval of a generation resource transaction. Based on the Companies' projected load growth, the Companies anticipate a capacity deficit of 1,005 megawatts (MW) by 2020, assuming Mon Power sells its interest in the Bath County facility.<sup>1</sup> This deficit grows to 1,439 MW by 2027 under the Companies' projections. Mon Power, in conjunction with an outside expert, developed a request for proposals (RFP) to solicit bids to reduce or eliminate this projected deficit. AE Supply, an affiliate of the Companies and owner of Pleasants, was deemed to have submitted the most attractive proposal. AE Supply has offered to sell Mon Power 100 percent ownership of Pleasants for \$195 million.

In the Petition, the Companies request a Commission Order approving the proposed transaction and seek rates to be implemented at closing that will result in an

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<sup>1</sup> On April 3, 2017, the Companies filed notice that a proposed sale of Mon Power's interest in the Bath County pumped storage project located in Warm Springs, Virginia, would not occur at this time.

immediate net revenue decrease of 1.6 percent. The net rate decrease includes an increase in the base rate component of the Companies' rates and a more than offsetting decrease in the fuel, purchased power and off-system sales component of the Companies' rates. The fuel, purchased power and off-system sales component of rates are determined and updated annually in an "Expanded Net Energy Cost" (ENEC) proceeding. Since the ENEC component of the Companies' rates related to Pleasants will likely change annually, it is not known if the 1.6 percent net rate decrease will continue at that level in the future. The Companies request a temporary transaction surcharge be implemented at the closing of the transaction that would remain in place until new base rates are implemented. In addition to the surcharge, the Companies propose an offsetting ENEC decrease until the next ENEC adjustment expected on January 1, 2019. Petition at 8-9.

## **II. BACKGROUND AND DISPARATE POSITIONS OF THE PARTIES**

The Petition by the Companies for approval to purchase Pleasants (the Transaction) from AE Supply brings into focus the collision of opposing viewpoints voiced in this proceeding by each party and their consternation over alternative viewpoints of other parties.

This proceeding exemplifies the most difficult type of case for the Commission. On the one hand, the outcome has potential adverse consequences to employees at Pleasants and their families and those working in support industries for Pleasants, to local, regional and even state economies, and to activities and the services that the Pleasants' jobs and taxes allow other political subdivisions to provide. On the other hand, opponents argue that the Transaction is "risky" and that granting the Transaction could have potential adverse rate and regulatory impacts on the customers of the Companies and on the Companies. These conflicting concerns are reflected in the sheer volume of prefilled testimony, the length of hearing transcripts and the magnitude and intensity of the briefs filed by the parties.<sup>2</sup>

The positions of the parties and their disparate interests, detailed in their testimony and briefs, reflect the diametrically opposed viewpoints of the Petitioners, the West Virginia Coal Association (WVCA), and the West Virginia Business and Industry Council (WVBIC) as contrasted with the positions of the Staff of the Commission (Staff), and the Intervenors who oppose the Transaction, the Consumer Advocate Division (CAD); Longview Power, LLC (Longview); West Virginia Solar United Neighborhoods/Community Power Network and the West Virginia Citizens Action Group (WVSUN/CAG); ESC Harrison County Power, LLC (HCP) and ESC Brooke County Power I, LLC (BCP) (together, HCP/BCP); Sierra Club and the West Virginia

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<sup>2</sup> Initial and Reply Briefs totaled nearly 450 pages; prefilled direct and rebuttal testimony totaled over 1,500 pages; the transcripts of the public comment and evidentiary hearing totaled over 1,500 pages, or a grand total of approximately 3,500 pages. By way of comparison, War and Peace, a novel by the Russian author Leo Tolstoy, is about 1,300 pages without end notes.

Energy Users Group (WVEUG) (being sometimes collectively referred to as Intervenors).<sup>3</sup>

It is not only the parties that disagree on the Transaction. The following sharply worded comments on the need for, or wisdom of, the Transaction reflect divergent positions obtained in public comment hearings conducted in this case by the Commission at Morgantown, Parkersburg and Martinsburg. Although not evidence, these comments provide insight on the generally fractured public reaction to the proposal.

### Environmental

#### Comments of Jason Lockard

#### SLS Land and Energy Development

Morgantown Tr. at 38: Approving this transfer will allow an exceptional power plant, one that already exceeds environmental standards, to continue operating in West Virginia.

#### Comments of Doug Renner, mechanic at the Pleasants Power Station

Morgantown Tr. at 22: For its age, Pleasants is probably one of your more environmentally friendly plants that you have in West Virginia.

#### Comments of George Powell

Martinsburg Tr. at 17: In 2006 the Pleasants plant had CO<sub>2</sub> emissions of 7,992,029 tons, sulfur dioxide emissions of 42,867 tons, nitrous oxide emissions of 9,512 tons and mercury emissions in 2005 of 328 pounds. These are environmental factors that kill 13,000 people a year in this country from power plants. There's a tremendous human cost to these coal-fired plants and we have to move into a direction that has cleaner energy for our people, for our children, for our grandchildren.

#### Comments of April Keating

Morgantown Tr. at 45: We have to watch out for our water and our public health. Evidence shows that coal poisons communities. Even if this plant follows all of the regulations, we know that a lot of the regulations are not sufficient.

<sup>3</sup> On December 11, 2017, Longview requested leave to withdraw its intervention in and be relieved from further participation in this case. The Commission will grant the request to withdraw. Longview's election to withdraw was made after testimony was filed, after discovery and after the evidentiary hearing and briefing were completed. While that is unusual, the Commission will grant the request, but the Commission clarifies that, although Longview is no longer a party to the case, it was a party prior to and during the evidentiary hearing, the Longview testimony was submitted and subject to cross examination pursuant to Commission process, and it is evidence that remains a part of the record in this case.

## Business Development

### Comments of Patsy Trecost, former Delegate, WV House of Delegates

Morgantown Tr. at 12: We're talking about 240 middle-class families with good job and benefits, but the impact for the community is much larger. Those families go to the grocery store and the car lot. Then, they purchase property, hire a contractor to build a home, and start a life for themselves.

### Comments of Mark Brazaitis

### Deputy Mayor of Morgantown, WV

Morgantown Tr. at 72: We need to attract top companies to our state and many of them have policies in place wherein they want renewable energy. The purchase of the Pleasants plant by Mon Power would be a step away from attracting those companies we desperately need to employ our citizens.

### Comments of Eileen Curfman

Martinsburg Tr. at 45-46: Customers are going to end up spending more for their electric bills to pay for this mistake. Our money could be spent on projects that bring us clean, efficient energy that create new jobs in expanding industries like solar and wind that would give our young people a future instead of hanging onto the few coal jobs that remain.

## Rate Impact

### Comments of Jody Murphy, Deputy Director, Pleasants Chamber of Commerce,

Parkersburg Tr. at 55: The rate increase being discussed is \$69 per year, or \$5 per month. I'll pay that gladly if it keeps 240 people employed. But, that rate increase is not true. Based on an economic study, the residential rate is expected to decrease by \$1 per month and the large industrial rate is expected to decrease three percent per month.

### Comments of Bill Ambrose

Parkersburg Tr. at 88: The Competitive market that Allegheny Energy Supply is in does not provide enough income for the plant to be profitable. The regulated environment of West Virginia would mandate rate increases until such time as the plant became profitable.

### Comments of Chris Craig

Martinsburg Tr. at 58: FirstEnergy is attempting to transfer an unprofitable, dirty plant from one subsidiary to another so the ratepayers of West Virginia can bail them out of their own unwise investments and outdated technology. This follows a similar transfer of the Harrison power station in 2013 that, according to the institute for energy economics and financial analysis, cost customers more than \$160 million.

### Employment

Comments of Eric Crossman, Principal Belmont Elementary School

Morgantown Tr. at 15: The 240 jobs matter to our community.

Comments of Jason Lockard

SLS Land and Energy Development

Morgantown Tr. at 38: To us, the Pleasants Transaction represents the chance to secure existing, high quality utility jobs that support hundreds, possibly thousands of jobs at companies that service the plant.

Comments of Kevin Campbell

Morgantown Tr. at 43: I feel for the people of Pleasants County and would like to see them all keep their jobs. And, they can keep those jobs as long as FirstEnergy retains the plant. But, to dump it on West Virginia ratepayers and expect us to cover the bill so that FirstEnergy stockholders can get dividends is just wrong.

### Need for More Generation Capacity and Energy

Comments of John Fitzpatrick

Mayor, City of Elmont, WV

Parkersburg Tr. at 29: Mon Power has shown that it needs more capacity to meet customer energy needs in years to come. The Pleasants Power Station is clearly the most cost effective purchase available to provide continued access to reliable, affordable, electricity.

Comments of Giulia Mannaria

Parkersburg Tr. at 27: This shortfall only occurs if Mon Power/ PE sees demand grow by more than two percent each year.

Comments of Consuelo Newman

Martinsburg Tr. at 63: Haven't we had enough of being stuck with corporate refuse? Are we not willing to make sound business decisions without being swayed by corporate and political expediency? Are we to be swayed by every company that dangles the carrot of jobs being given or taken away? We do not need this plant. Mon Power and PE are able to purchase electric power from the PJM grid if needed.

### Value to Stakeholders

Comments of Mike Wells

Superintendent of Pleasants County Schools

Parkersburg Tr. at 49-50: If the plant closes, Pleasants County will lose \$5.5 million in taxes to our school system as well as our community and county government. If the plant closes, it would impact school enrollment, which is already decreasing.

Comments of Erik Engle

Parkersburg Tr. at 19: This transfer from the Ohio unregulated energy market to the West Virginia regulated energy market is about maintaining profitability for the Executives and Board of FirstEnergy. It is not about what is best for those who receive services from FirstEnergy's subsidiaries in West Virginia.

The Commission has thoroughly reviewed the entire record, including the testimony, exhibits and briefs of all parties. We cannot specifically mention each and every piece of testimony, exhibit, or argument in our discussion in this Order, but all positions were fully considered. Although not a complete summary of the positions of the Parties, the following excerpts from the briefs and testimony of the parties provide a further glimpse of the chasm that separates the Companies from Staff and the Intervenors in this case (we offer these excerpts on pages six through eleven without comment, other than *caveat lector*):

#### A. POSITIONS OF PARTIES URGING APPROVAL OF THE TRANSACTION

##### 1. The Companies:

[T]he Transaction will bring many benefits to the State beyond the positive rate impact. Acquiring Pleasants will help preserve employment at Pleasants and at the mines and services suppliers it relies upon — protecting \$400 million in annual economic impact and approximately 600 West Virginia jobs (including 240 at Pleasants alone) at a time when the State's struggling economy is finally showing signs of life. Dr. John Deskins, director of the West Virginia University Bureau of Business and Economic Research ("BBER"), calculated and supported this economic impact figure, and leaders of the West Virginia Coal Association and the West Virginia Business and Industry Council emphatically supported the Transaction for its economic development and job preservation attributes. Another key benefit is Pleasants itself: it is a strong performing asset, and having previously owned it for decades, Mon Power knows it well. Pleasants is well maintained, has a full complement of environmental controls, is even newer than Mon Power's two other baseload facilities, and has benefited from a highly structured maintenance program administered by a dedicated work force.

Yet acquiring Pleasants is not an economic preservation initiative. Instead, the Companies' proposal arises from a legislatively-mandated integrated resource planning [IRP] process, repeated analyses of the Companies' capacity position, PJM market developments such as Capacity Performance, and a structured and independent RFP process. This process, which extends back to 2015 when the West Virginia Legislature's IRP legislation (W. Va. Code § 24-2-19 ("IRP Act")) went into effect, resulted in the identification of Pleasants as the most cost-effective means to address a looming capacity deficiency. It reflects the Companies' efforts to fulfill their obligations as Commission-regulated electric utilities to own capacity resources sufficient to ensure a continuing physical hedge against PJM market risk — obligations that this Commission enunciated in its October 2013 order approving Mon Power's acquisition of the Harrison plant and that the West Virginia Legislature reinforced in the IRP Act.

Companies Initial Brief at 2-3 (footnotes omitted) (briefs of the Parties will be cited by abbreviation by party, whether Initial or Reply and page number, such as "Cos. Init. Br. at 2-3") (prefiled testimony of the parties will be cited by witness, exhibit and page number, such as "WVCA WBR-D at 4" and transcript references will be cited by Transcript volume and page number, such as "Tr. I at 32").

2. The WVCA:

Of the nearly 3.5 million tons [of coal] bought and burned annually [at Pleasants], currently approximately 80% is coming from operations in West Virginia. West Virginia coal companies compete with other neighboring states' coal, such as Ohio coal production located very near to Pleasants. But it is good for West Virginia miners, and related industries and consumers, that Pleasants is primarily buying and burning West Virginia coal, similar to Mon Power plants.

• • • •

Pleasants Power is critically important to companies producing coal in central and northern West Virginia because it provides certainty for coal suppliers, coal consumers, and prevents the loss of hundreds of coal jobs. It helps the local and state economies, including the troubled West Virginia state budget.

• • • •

[I]t [the Transaction] will preserve a market for nearly 3-4 million tons of coal, as well as the jobs associated with the production, cleaning and transportation of the coal to the Pleasants Plant and the tax revenue that accompanies that economic activity. The ancillary workforce created and supported by coal mining employment is probably about double the number employed by producing the 3-4 million tons of coal needed by Pleasants per year. By moving the Pleasants Plant to the regulated baseload of West Virginia's utilities, that would bring more stability, certainty, and dependability to the West Virginia coal industry, the local community, and West Virginia users of electricity.

WVCA WBR-D at 4-5.

3. The WVBIC:

First, it is easy to see how Pleasants' continued operation contributes to preserving employment opportunities for the West Virginia workforce. In the direct testimony of John Deskins filed with the Application in this case, he calculates that a closure or deactivation of Pleasants would result in a loss of nearly \$400 million in annual economic impact, with a job loss of

approximately 600 people and \$48.2 million in employee compensation. These numbers are staggering, and [WVBIC] believes that among the Commission's considerations in this case, the preservation of this economic activity should be a very substantial factor. To maximize job development opportunities, [WVBIC] has encouraged state leaders to promote regulatory consistency and to incorporate economic impact assessments in legislative deliberations, investigating the net immediate and long-term effects of legislative proposals. We believe that in the Commission's consideration of this Application, these factors should also come into play (and judging by past Commission decisions such as Mon Power's acquisition of an interest in the Harrison power station, we believe the Commission has done so in the past).

The second focus area for [WVBIC] is fiscal responsibility. The Commission is certainly aware that recent headwinds in revenue collections have complicated the efforts of Governor Justice and West Virginia lawmakers to manage the State's budget. West Virginia can ill afford to overlook current contributors to the state and local tax base in West Virginia. Dr. Deskins calculated that the overall economic activity associated with Pleasants' continued operation is estimated to be nearly \$20 million dollars annually in selected state tax revenue, including \$12 million dollars in B & O tax alone.

Third, [WVBIC] and its members have advocated infrastructure improvement as a critical underpinning of West Virginia's economic future. Financing short and long-term infrastructure improvements and investigating opportunities to encourage such investment is in the interest of every West Virginian. Of course, maintaining a healthy tax base and supporting high-paying employment opportunities is critical to state efforts to invest in the future through infrastructure improvement.

WVBIC CH-D at 3-4.

## B. POSITIONS OF PARTIES URGING DISAPPROVAL OF THE TRANSACTION

### 1. The Staff:

The Commission is faced with an incredibly difficult decision in this case where [the Companies] . . . are seeking prior consent and approval to enter into an agreement to purchase the Pleasants generating plant from Allegheny Energy [Supply] (AES), an unregulated affiliate. Granting approval of this transaction comes with certain risks tied to assumptions about load growth and increasing PJM market prices. Once the transaction has been approved, it is like jumping off a cliff, and those assumptions better be correct or it could be extremely costly for ratepayers and the State as a whole. Denying approval of the transaction, however, comes with its

own set of risks of exposure to the PJM markets and the potential loss of a valuable economic asset. In this brief, Staff provides the Commission a blueprint of the interplay amongst those competing risks and benefits. In the end, Staff concludes the risks associated with purchasing this plant outweigh the potential benefits the transaction could supply and the risks associated with denial are risks worth taking. Staff believes the Companies, their ratepayers and the State as a whole would be better off with the Companies relying on market purchases to fulfill any capacity or energy shortfall that occurs in the near term, with the opportunity to revisit that decision at any time. Staff recommends the Commission conclude approving this transaction is not reasonable and that it will adversely affect the public in the State. Staff recommends the Commission deny approval of the transaction under the standard espoused in West Virginia Code §24-2-12.

Staff Init. Br. at 1-2.

2. The CAD:

The transaction . . . should not be approved [because] the statutory requirements of W. Va. Code §24-2-12 have not been met; the transaction will adversely affect the consuming public because the transaction will burden ratepayers with the cost of maintaining and operating an approximately 37-year-old, uncompetitive coal plant that cannot be sold to a fair market purchaser; the terms and conditions of the transaction are not reasonable because the acquisition of the Pleasants Power plant is not the most cost-efficient way to meet the Companies' future energy needs; and the transaction does not satisfy the undue influence test because the RFP was biased in favor of Pleasants and the RFP was administered by an "independent" company which has millions of dollars of contracts with FirstEnergy (the Seller) and ran an RFP process designed to achieve a specific result.

For these reasons, it is the position of the [CAD] . . . that Mon Power's acquisition of the Pleasants plant is not in the best interests of Mon Power's customers, which is and should be the primary consideration in this case. Further, the proposed transaction, as currently configured, fails the undue influence test. The transaction should be denied.

CAD Init. Br. at 2-3.

3. Longview:

[T]he transaction as requested is not supported by the facts. Rather, the evidence shows that: 1. the asserted need for Pleasants as a capacity hedge is not supported by the evidence; 2. the process utilized by The

Companies to fill this asserted need was flawed; and 3. even if the Commission believes it is appropriate to consider approval of the requested acquisition, such approval should not be granted until a full engineering analysis has been conducted of the facility to be acquired. Further, the evidence shows that if approved, it is likely that ratepayers will be asked to fully absorb above-market costs for their electricity and ultimately bear the cost of rehabilitating an aging power production facility. Finally, the Commission should refrain from issuing its decision until The Companies' companion FERC proceeding is resolved.

Longview Init. Br. at 2.

4. HCP/BCP:

A key component to any good portfolio approach to achieving rate stability is diversification. As Mon Power discusses in their response to the West Virginia PSC Staff First Request for Information, the predominant fuel of new generation in PJM is natural gas and wind. The decision to add new wind and natural gas capacity is based on these fuel sources having the lowest energy production cost and most favorable economics. A PPA [purchased power agreement] with new state of the art gas plants is a good way for Mon Power to diversify the fuel profile in its generation portfolio. Counter to Mon Power's position, it seems to make little sense from a low cost rate stability perspective to continue to add more coal to Mon Power's generation portfolio. [Citation omitted.]

Further, PPAs can be structured so that Mon Power can benefit from off-system sales. A PPA can be structured so that Mon Power contracts for the ability to dispatch the plant for more energy than they project that they require. This would provide Mon Power the opportunity to sell the power into the PJM market for off-system sales so that they can realize a profit from those sales when they are economic.

HCP/BCP Init. Br. at 7.

5. WVEUG:

This case presents a number of complicated and difficult questions for the . . . [Commission] . . . . The questions posed pertain to the fair value of the Plant, the efficacy of the Request for Proposals ("RFP") conducted by Mon Power, the net present value ("NPV") impact that the transaction may have on West Virginia citizens, the competitiveness of the Plant in the PJM Interconnection, LLC ("PJM") market, and even the potential impact that the Plant's closure might have on the West Virginia economy. These questions ultimately present the issue of the reasonableness of a large, multi-state corporation transferring a generation asset from a wholesale

supply arm, where the asset has been deemed to be too risky, to a fully-regulated distribution utility, where the costs of the Plant are guaranteed to be recovered from a captive ratepayer base.

WVEUG Init. Br. at 1.

6. Sierra Club:

With its proposal to purchase the Pleasants Power Station, Mon Power has managed to unite a diverse assemblage of groups that represent widely differing viewpoints. Environmental groups, renewable energy advocates, large industrial energy users, residential customers, power-plant owners, citizen watch-dogs, and even the Commission's own staff have come together with a single-coherent message: *the proposed purchase of the Pleasants plant is bad for West Virginia.*

Intervenors in this action are not natural allies. The witnesses they present, however, are remarkably consistent in their testimony regarding flaws in Mon Power's petition. Almost without exception, witnesses for these parties agree on the following: 1) Mon Power has exaggerated (if not artificially manufactured) the need for future capacity; 2) the method Mon Power used to find assets to meet its purported capacity shortfall was extremely limited (if not outright biased); and, most importantly, 3) the asset chosen as a result of this method represents a serious risk to West Virginia ratepayers.

Sierra Club Init. Br. at 1 (italics in original text).

7. WVSUN/CAG:

The Companies' proposal reflects FirstEnergy's so-called exit strategy from the competitive power business. As a merchant plant, the profitability of Pleasants is tied to the revenues it receives from the wholesale markets. AE Supply (and, ultimately, FirstEnergy and its shareholders) bear the market risks associated with the plant. In recent years, market conditions have turned unfavorable for aging coal plants like Pleasants as a result of lower market prices for energy, capacity, natural gas, and renewable resources. Faced with this situation, FirstEnergy now seeks to transfer the plant to its regulated utility subsidiaries, the Companies, whose customers would bear the plant's market risks. If approved, the transaction would entail a complete shift of cost and risk from FirstEnergy shareholders to West Virginia ratepayers. As such, the beneficiaries of this transaction are FirstEnergy and its shareholders, not West Virginia ratepayers.

WVSUN/CAG Init. Br. at 1.

### **III. JURISDICTION OF THE COMMISSION**

The record is replete with arguments about why the Commission should or should not approve the Transaction, but no party seriously contested the right of the Commission, in the first instance, to decide this case under W.Va. Code §24-2-12 and other pertinent provisions of Chapter 24 of the West Virginia Code. The Parties, however, have their own interpretations of what the West Virginia Code mandates or authorizes this Commission to do in this case.

All Parties acknowledged that the provisions of W.Va. Code §24-2-12 apply and were not at all reluctant to advise the Commission (either narrowly or broadly) of the meaning and import of the statutory authority of the Commission with respect to the Transaction:

If the Transaction provides economic and customer benefits, the price is fair, and the factors set forth in §24-2-12 are met, then the seller's motivation should be of no concern and the Commission should approve the Transaction.

Cos. Init. Br. at 54.

Because the proposed transaction would involve Mon Power's acquisition of Pleasants from AE Supply, a FirstEnergy corporate affiliate, the Companies must obtain the Commission's prior consent and approval. W. Va. Code §24-2-12(f). Such approval can only be granted if the Companies establish that 1) "the terms and conditions thereof are reasonable," 2) neither party to the transaction has "an undue advantage over the other," and 3) the transaction does "not adversely affect the public in this state." W. Va. Code §24-2-12 (emphasis added.)

WWSUN/CAG Init. Br. at 3.

Asset transfers, such as the one now sought by FirstEnergy, may be approved only if the party seeking approval of the transfer makes a "proper showing" both (1) "that the terms and conditions thereof are reasonable," and (2) "that neither party is given an undue advantage over the other, and do not adversely affect the public in this state." W. Va. Code § 24-2-12. Such asset transfers are, moreover, "void to the extent that the interests of the public in this state are adversely affected." *Id.* Accordingly, absent a showing [by] Mon Power that the proposed transfer will not harm the public interest the Petition should be denied.

Sierra Club Init. Br. at 4.

The controlling statute for this proposed affiliated transaction is W. Va. Code §24-2-12. "The commission may grant its consent . . . upon a

proper showing that the terms and conditions thereof are reasonable and that neither party thereto is given an undue advantage over the other, and do not adversely affect the public in this state.” The Commission previously described review under this statute as a forward-looking evaluation of functioning of the utility after the transaction is closed. The Commission stated,

The other two tests for evaluating utility agreements under W. Va. Code §24-2-12 require the Commission evaluate and assess whether the terms and conditions of the transaction are reasonable and whether the transaction adversely affects the public in this state. These two conditions are in a sense intertwined, and it is difficult to see how unreasonable terms and conditions would not adversely affect the public in this state. While this test is an attempt to assess the transaction as structured, it also has a “forward-looking” element to it and requires that the Commission evaluate how the new utility will function after the transaction is closed.

Staff Init. Br. at 12.

The CAD takes no prisoners in its attempt to “advise” the Commission of its responsibilities. In its Reply Brief, the CAD emphasizes the gravity of the situation by stating that, if this Transaction is approved, “the harm that redounds to West Virginia captive ratepayers will be a legacy of this Commission.” CAD Rep. Br. at 1.

As indicated above, the polar star guiding the Commission in cases such as the instant one is the protection of ratepayers from the affiliate transactions. The bulk of the evidence shows that the transaction at issue will not benefit ratepayers, but rather burden them with the significant financial support of an uncompetitive, unnecessary, and aging coal plant with operating costs which will only continue to increase. While the companies claim that no other bids come anywhere near the low, winning bid of Pleasants, the harm to ratepayers is caused by the narrow RFP that ensured that Pleasants would have no meaningful competition, and therefore, would win. The evaluation of the bids is just further evidence that the RFP was not objective or resulted [sic] of an arm's length transaction between the Companies and affiliate seller, AE Supply.

CAD Init. Br. at 6.

The Commission routinely confronts the oft-used terms of W.Va. Code §24-2-12 that require a utility seeking an affiliate transaction such as the one before us to make a “proper showing that the terms and conditions thereof are reasonable and that neither party thereto is given an undue advantage over the other, and do not adversely affect the public in this State.” These terms are de rigueur statements in petitions in all W.Va. Code §24-2-12 filings and in filings in this case. While these terms are obviously the essence of W.Va. Code §24-2-12, they are not, and cannot be, precisely measured and

must be considered in conjunction with the facts of each transaction and in the light of other provisions of Chapter 24 and decisions of the Courts. It is only in the context of the facts and circumstances of a particular transaction that these terms take on substance and meaning.

Further, our specific charge in applying W.Va. Code §24-2-12 must also be viewed through the lens of W.Va. Code §24-1-1, the statutory provision that describes the Legislative purpose and policy for the existence of the Commission. It is vital to remember that the critical language of W.Va. Code §24-1-1(b), as it relates to this case and to W.Va. Code §24-2-12, is that the Commission, in making its deliberations and decisions, should

- Exercise legislative powers delegated to it by the Legislature; and
- Appraise and balance the interests of current and future ratepayers, the State's economy and the utilities subject to its jurisdiction.<sup>4</sup>

In this case, the Commission has had an enormous amount of testimony from a plethora of experts, all suggesting that they know (and are willing to explain to the Commission) exactly the deficiencies and risks<sup>5</sup> inherent with the Companies' case. We will discuss these arguments later in the Order (and the responsive position of the Companies), but in most instances, these experts, with the exception of Staff witness Terry Eads, offered no hard review or specific financial analysis of the Companies' proposal. They relied, instead, on their backgrounds and special expertise to advise the Commission about what they think should be, or should have been, done and what they perceived as shortcomings or failures of the Transaction of the analysis.

Many of the Companies' supporting arguments for the acquisition are based on its witnesses' views of the PJM market for capacity and energy. Many of the Intervenors oppose the Transaction based on their views of the same PJM market, and these views are significantly different from those presented by the Companies. Unfortunately, no one knows what the markets will do.

The Staff agreed:

Crystal balls do not exist. Any one telling this Commission for certain this transaction is a sure winner or a sure loser is fooling themselves. No one really knows what the future holds. The Commission must carefully consider what is evident from the past, be mindful of the

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<sup>4</sup> The Legislature creates the Public Service Commission to exercise the legislative powers delegated to it. The Public Service Commission is charged with the responsibility for appraising and balancing the interests of current and future utility service customers, the general interests of the state's economy and the interests of the utilities subject to its jurisdiction in its deliberations and decisions. W.Va. Code §24-1-1(b).

<sup>5</sup> See discussion of "Risks," supra at 38-39, 49-50.

likely future and be careful not to bind ratepayers to unnecessary long-term risks. Our recent past with these types of transactions tells us we should tread lightly, because even though the Staff analysis shows this transaction is a positive, there are very real risks that could quickly turn the positive into a negative.

Staff Init. Br. at 29.

As we indicated, there are no precise metrics against which we can assess every transaction that comes before the Commission under W.Va. Code §24-2-12 or that we can use to label these transactions as either “pure and holy” or the “devil’s spawn.” The Commission must examine each transaction in the light of the facts, always mindful of our statutory purposes and authorities. We measure, we balance, we assess countervailing interests, and we apply our best judgment. We have found that there is generally no single item or factor that is the “on/off” switch for approval and disapproval of these types of transactions.

We consider the record and the provisions of W.Va. Code §24-2-12 and utilize the balancing of interests required under W.Va. Code §24-1-1(b). Unfortunately, most of the Intervenors seem to have discounted the legislative guidance under W.Va. Code §24-1-1(b), particularly for the benefits provided, and focused only on W.Va. Code §24-2-12. There was little, if any, analysis provided by the Intervenors about the balancing of the interests of current and future ratepayers, the State’s economy and the utilities subject to our jurisdiction.

The Companies, in fact, commented in their Initial Brief specifically on that lack of evidence or discussion about benefits from the Transaction:

Pleasants opponents all but ignore the benefits the Transaction will provide to customers. Holly C. Kauffman, President of West Virginia Operations, identified these benefits in her direct testimony. First and foremost, the Transaction will cover the Companies’ capacity deficiency through 2027 based on current load forecasts. The acquisition will also provide the physical hedge against volatile market prices that Mr. Ruberto explained, the opportunity for net revenues from generation sales that will serve as direct offsets to ENEC costs, and an enhancement of Mon Power’s asset base and overall capitalization that could benefit customers through more favorable financing terms. And, the transaction that provides these benefits will also permit an overall reduction in customer rates, as the projected ENEC rate reduction will more than offset the impact of the Temporary Surcharge. Kauffman direct testimony (Co. Ex. HCK-D) at 9-10.

*2. The Transaction will benefit the State of West Virginia.*

The Transaction's benefits to the State are manifest. Approving the Transaction and maintaining plant operations will preserve hundreds of jobs (at the plant, in mining, and in other supporting businesses) and positively impact the state's economy. Dr. Deskins and witnesses for the West Virginia Business & Industry Council and the West Virginia Coal Association have attested to this. For example, at the hearing, Dr. Deskins highlighted how a Pleasants closure would affect West Virginia's employment levels:

- A. Just for scale, during the suffering that our state has seen from 2012 through the middle part of last year, we lost about 26,000 jobs.
- Q. That's statewide?
- A. Statewide. But in the recovery that we've seen over the last year or so, we've gained back 4,500 jobs. So if we were to lose 600 jobs, you just think about how much it would reduce that 4,500 improvement that we've seen over the last year.

Tr. I at 282. Chris Hamilton, Chairman of the West Virginia Business & Industry Council, contended that "jobs, development, infrastructure improvement, and fiscal responsibility – are all advanced through Pleasants' continued operation." Hamilton direct testimony (WVBIC Ex. CH-D) at 1. Bill Raney, President of the West Virginia Coal Association, stated [that the] continued operation of Pleasants "provides certainty for coal suppliers, coal consumers, and prevents the loss of hundreds of coal jobs." Raney direct testimony (WVCA Ex. WBR-D) at 4. Conversely, at hearing Mr. Raney expressed his concern if the Transaction is not approved:

[M]y fear is that it would be, that it's likely to close. And, you know, the implication of that is the – or the [multiplier] effect of that is you take 500, 600 coal miners and you're putting them out of work. That's the real interest of us being involved in this case.

Tr. V at 14. It is no surprise, then, that the Transaction enjoys broad support among those for whom jobs, tax base, and economic development are important considerations.

Conversely, Transaction opponents ask the Commission to determine that if no one can prove Pleasants will close, then the benefits of its continued operations are illusory. Certainly the shut-down of Hatfield Power Station, numerous West Virginia power stations, and power stations

across the region are real, not illusory. Moreover, the loss of baseload generation has caused great concern now at PJM and the Federal government. The U.S. Department of Energy's proposal to provide incentives to baseload coal and nuclear plants to protect the resiliency of the power grid is an example of this concern. Tr. V (Hamilton) at 19.

Gambling on the future of Pleasants does not trouble intervenors such as WVSUN-CAG and Sierra Club, whose objective is to shutter Pleasants. Mr. Comings, the Sierra Club witness, acknowledged Sierra Club's "Beyond Coal" campaign, which keeps a running total of the coal plants it claims to have help kill and a countdown of the remaining plants it hopes to defeat. His client has "targets for coal retirement[s]," he said. Tr. III (Comings) at 170-71. In fact, perhaps the strongest indication that the future of Pleasants is uncertain is Sierra Club's extensive participation in this case. Sierra Club did not intervene because it is concerned with the Companies' customers, the stability of their rates, or the State's economic well-being. Sierra Club's narrow-minded fixation is on stopping anything it believes might lead to the continued operation of a coal plant. Simply put, if closing Pleasants were not a potential outcome, Sierra Club would not be in this case.

Cos. Init. Br. at 41-43.

We have found one of the curious anomalies of major regulatory proceedings before this Commission to be the apparent reluctance of parties to afford weight to "public policy considerations"<sup>6</sup> for a Transaction, but which they readily recognize for ratemaking considerations. The Commission has experienced no similar reluctance in small transactions where the Commission gives significant credence and import to the loss or gain of employees or other factors such as the location or opening of another office in West Virginia that might impact a community or cause an increase or retention of local employees. Part of that reluctance in larger transactions may spring from the difficulty of weighing or balancing those local or regional externalities against rate or financial impacts that may fall on a large regional or statewide customer base, but we have viewed externalities that implicate the statutory purpose set forth in W.Va. Code §24-1-1(b) as a valid concern and factors in considering transactions. These factors, which are "external" from the interests of current ratepayers, are in the interest of future ratepayers, the interest of the State's economy and the interests of the utility, which were clearly considered of import to the Legislature when enacting W.Va. Code §24-1-1(b).<sup>7</sup>

<sup>6</sup> These public considerations are sometimes referred to as "externalities," a shorthand expression to describe an array of non-ratemaking implications about employment and jobs, enhancing and preserving the attractiveness of the State as a place for industry to do business, attracting new offices, creating productive capacity, tax base, and support to local and regional charities and providing governmental financial support and a host of other outcomes, other than rate impact, that can occur because of Commission proceedings.

<sup>7</sup> The Commission when considering the outcome of cases has considered these types of external factors. Eastern Systems Corp. and Monongahela Power Co., Case No. 00-0067-G-PC (Comm'n Order 5/11/00);

In this instance, the immediate local, regional or (arguably) statewide externalities to the Transaction are significant. We are not contending that those externalities, taken alone, tip the balance in favor of approving the Transaction, but we do believe that they are genuine, germane and real factors that the Commission can and should consider, weigh and balance in making its decision to approve, conditionally approve, or deny this, and other, petitions.

We discussed at length the nature of the Commission's authority in the Commission case Century Aluminum, Case No. 12-0613-E-PC (Order of October 4, 2012) ("hereinafter Century Aluminum Order at \_\_\_"), <http://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=354671>, involving a request to implement a special rate for energy-intensive industrial customers under the provisions of the Energy Intensive Industrial Consumer Revitalization Tax Credit Act (W.Va. Code §11-13CC-1); and an amendment to W.Va. Code §24-2-1j. As we stated in Century Aluminum:

After enactment of the 1913 legislation, various cases were brought before the Court challenging the authority of the Commission to fix rates. Among other things, the Court held that the Legislature's delegation of authority to the Commission was constitutional; that the rate orders of the Commission were akin to an act of the Legislature; that the Legislature intended the Commission to be the body in State government that would determine the public interest from the perspective of the regulated utilities, current and future ratepayers and the State; and that, because of the legislative nature of the Commission orders, the Court's review (which was not reviewed upon appeal, but rather reviewed by original process under W.Va. Code §24-5-1) was limited so as not to give the Court the power to substitute its judgment for that of the Commission. United Fuel Gas Co. v. Public Serv. Comm'n, 73 W.Va. 571, 80 S.E. 931 (1914). The Court, in United Fuel, recognized that the Legislature was directing the Commission to assume duties that were important, technical and complex.<sup>8</sup>

Century Aluminum Order at 11.

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Frontier Communications Corp., et al., Case No. 09-0871-T-PC (Comm'n Order 5/13/10); Monongahela Power Co., et al., Case No. 10-0713-E-PC (Comm'n Order 12/16/10); and PNG Companies LLC and Equitable Gas Co., LLC, Case No. 13-0438-G-PC (Comm'n Order 11/8/13).

<sup>8</sup> The West Virginia Supreme Court observed (and the Commission is partial to this observation):

The salaries which the statute attaches to the office of the Commissioners, and the nature of the subjects to be dealt with by them, all imply that only persons of the requisite qualifications should be appointed, and that after appointment they should by investigation and study become further qualified by learning and experience, indeed should become experts upon all subjects and businesses coming within their jurisdiction.

United Fuel Gas Co. v. Public Serv. Comm'n at 581-582.

In furtherance of the Commission's legislative responsibilities, our analysis and rulings on the Transaction are not limited to examining whether the Transaction makes only economic or rate and ratemaking sense. We can also, within the authority granted us by the West Virginia Code, examine and balance externalities to help us assess the impact and merit of transactions that come before us as long as our decisions examine and balance fairness and reasonableness of the transaction and balance the interests of current and future utility service customers, the general interests of the State's economy and the interests of the utilities as a part of our examination of the affiliated contract to determine whether "the terms and conditions thereof are reasonable and that neither party thereto is given an undue advantage over the other, and do not adversely affect the public in this State."<sup>9</sup> We believe that these externalities are valid factors for consideration in determining whether to approve the Transaction.

The Legislature has taken significant steps to structure the Commission to safeguard the "public interest" for the ratepayers, the regulated utilities, and the State's economy, recognizing that those public interests are entitled to the safeguards of due process and equal protection and the protection from undue or unreasonable discrimination.

As we indicated in Century Aluminum:

The West Virginia Supreme Court quoted with approval a statement of the United States Supreme Court holding that:

[T]he rate-making power necessarily implies a range of legislative discretion; and, so long as the legislative action is within its proper sphere, the courts are not entitled to interpose and upon their own investigation of traffic conditions and transportation problems to substitute their judgment with respect to the reasonableness of rates for that of the legislature or of the railroad commission exercising its delegated power.

United Fuel Gas Co. v. Public Serv. Comm'n, 73 W.Va. at 582, 80 S. E. at 936, quoting Louisville & N.R. Co. v. Garrett, 231 U.S. 298, 58 L.Ed. 229 (1913).

Century Aluminum Order at 12.

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<sup>9</sup> We believe the W.Va. Code §24-2-12 provision about "undue advantage" is frequently misunderstood. While we are cautious in assessing the reasonableness and fairness of transactions, we believe the provision that "neither party has been given an undue advantage over the other" involves an after the fact assessment of the transaction terms and conditions and is not meant to bar or make all affiliated transactions unfair or suspect. Several parties have suggested that this means that affiliated transactions are almost unfair *per se* and that there is a much higher test on fairness or reasonableness because a transaction involves an affiliate. We disagree. See discussion supra at 47-49.

#### **IV. PROCEDURAL HISTORY**

The Procedural History, including parties, filing dates, list of witnesses and notices made in this case, is set forth in Appendix A attached to and incorporated into this Order.

#### **V. ISSUES PRESENTED BY THE PARTIES**

In this section, the Commission will outline most of the significant issues identified by the Parties in the record.

##### **A. Is There a Need for Capacity?**

###### **1. The Companies Argue that the Commission and the IRP Act Require Additional Capacity.**

The Companies argue that they need additional capacity. They also urge that language in the Harrison Order<sup>10</sup> and the legislative requirement for an IRP require the Companies to ensure the ownership of capacity in excess of load (Cos. Init. Br. at 6-8):

Even though the Harrison acquisition would give Mon Power a ratio of installed capacity to load well over 100%, the Commission recognized that “[t]he addition of baseload units results in a jump in reserve capacity that is then gradually reduced over time as internal load grows.”

Cos. Init. Br. at 7 (citing Harrison Order at 24).

The Companies also note that the Commission in Harrison found that customers receive “the benefit of off-system sales that are made from the reserve capacity.” Id. (citing Harrison Order at 24).

Staff argues that the Companies do not need 1,300 MW of capacity within the next ten years, but acknowledges that the Companies may need some level of capacity in the short term. Staff Init. Br. at 5. Although Staff did not project specific capacity needs for the Companies, WVSUN/CAG projected that the Companies’ peak demand will not meaningfully exceed its currently-owned capacity until 2021 with the projected deficit climbing to only 267 MW by 2025. WVSUN/CAG Init. Br. at 16; WVSUN/CAG Cross Ex. 2 at 89.

###### **2. What is the Projected Load Growth in West Virginia Territory?**

According to the Companies, projections of vigorous growth in the service territories have caused their projected capacity shortfall to appear sooner than previously

<sup>10</sup> Monongahela Power Co. and The Potomac Edison Co., Case Nos. 12-1571-E-PC and 13-1272-E-PW, Comm’n. Order, October 7, 2013 (Harrison Order), at 24, aff’d, West Virginia Citizens Action Group v. Public Serv. Comm’n., 758 S.E.2d 254 (W.Va. 2014).

predicted. Bradley D. Eberts, Manager of Load Forecasting at FirstEnergy Service Company, testified about the Companies' load peak demand forecasts, incorporating expected rates of economic growth from BBER's 2017 West Virginia Economic Outlook report and adjustments for projected industrial energy usage based on information developed by the Companies' customer support representatives. Cos. Ex. BDE-D at 5-6 and 8-10. Dr. Deskins, who used the BBER information attributed to the counties within the Companies' service territories, found that between 2016 and 2031, economic progress would be more optimistic for most counties served by the Companies than for West Virginia as a whole, stating:

The Companies' service territories will be buoyed by segments of the state's economy that should see sustained growth during the next 15 years. These include the natural gas industry, as continued development of the Marcellus and Utica Shale create growth opportunities throughout the state, particularly in the Northern Panhandle and portions of the North Central Region. The North Central Region's economy should also experience relatively steady growth over the course of the outlook period thanks to its relatively diverse economic base, pool of skilled and educated labor as well as infrastructure improvements that open access to commercial and industrial development. The state's Eastern Panhandle Region is also expected to realize a stronger pace of growth compared to the state average as it is connected to the highly-developed Greater Washington D.C. area's economy, and also enjoys healthy population growth thanks to net in-migration of people from higher cost-of-living areas in neighboring Maryland and Virginia.

Cos. Ex. JD-D at 7.

Staff counters that the Companies are projecting an unprecedented level of load growth within the next ten years during a time of flat load growth across the PJM footprint. Staff Init. Br. at 5. Staff noted that Companies' witness Eberts testified that the Companies' winter peak is expected to increase from 2,867 MW in the 2016/17 delivery year (DY)<sup>11</sup> to 3,752 MW by the 2027/28 DY – a thirty-three percent increase in winter peak. Furthermore, the Companies project winter peak to grow from the same 2,867 MW in the 2016/17 DY to 3,421 MW in the 2020/21 DY – nearly 600 MW in only four years. Staff Init. Br. at 6; Cos. Ex. BDE-D at 3. By comparison, in the Harrison case (Case No. 12-1571-E-PC), the Companies predicted summer peak to grow from 2,578 MW in 2012 to 3,025 MW in 2026, a more modest growth of 450 MW over fourteen years. The analysis switches from winter peak to summer peak between the present case and the Harrison case because the Companies used summer peak in the Harrison case.

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<sup>11</sup> PJM uses a split calendar year planning year, which is referred to as a Delivery Year (DY). PJM defines the DY as the twelve-month period from June 1 to May 30 of the following year.

Staff argued that the Companies are projecting this load growth will be driven mainly by the shale activities in northern and central West Virginia without losing any load to the natural gas industry or other factors. Staff Init. Br. at 6. Staff argued that it is not credible that the natural gas will continue to expand without any impact on the Companies' operations or that the natural gas expansion will not impact the coal industry and its ancillary businesses. Id. The Companies' NPV analysis is predicated on rising natural gas prices. Staff argued that the Companies cannot have it both ways – either the load will increase because of expansion of natural gas facilities and downward pressure on natural gas prices will continue or natural gas expansion will slow and the load will not materialize. Staff Init. Br. at 6.

### 3. Is there a Capacity Shortfall?

Mon Power issued its IRP in December 2015, but states that it continued to evaluate its generation portfolio, with a new emphasis on the recently-implemented PJM "Capacity Performance" (CP) market design approved by FERC in June 2015. Cos. Init. Br. at 10. CP rules provide that generator resources with capacity obligation that fail to perform when needed to maintain reliability during peak demand periods are subject to significant penalties. Cos. Ex. JAR-D at 5, citing PJM Interconnection, LLC, 151 FERC ¶ 61,208 (2015), order on reh'g, 155 FERC ¶ 61,157 (2016). Mon Power determined that the CP market would have a significant effect on the value of its direct interest in the Bath County pump storage project located in Warm Springs, Virginia, possibly eliminating it from being counted as replacement capacity for Mon Power generation resources in the APS Zone. Cos. Init. Br. at 10. This development caused the Companies to update their load and capacity forecasts, resulting in a projected capacity shortfall of approximately 785 MW by DY 2020-21 and 1,219 MW by DY 2027-28. Id. at 11.

The Companies argue that capacity resource planning based on PJM summer peaks, rather than the winter peaks actually used by the Companies, would substantially underestimate the Companies' actual peak demands and would fail to account for the important differences between PJM's broad APS Zone forecast and the service territory-specific economic growth, distributed solar generation penetration, and weather factors considered by Mr. Eberts. Cos. Init. Br. at 11; Cos. Ex. BDE-R at 2-9. The Companies are winter-peaking utilities and argue that the IRP Act requires them to focus on their actual peaks. JAR-R at 5. The Companies argue that the difference between their winter and summer peaks is a relatively insignificant amount in terms of long-term resource planning, but insist that the capacity projections based on the Companies' actual peaks best reflect the Companies' appropriate capacity levels and reserve margins and best address their customers' specific needs. Cos. Init. Br. at 12.

Staff, on the other hand, argues that using winter peak loads instead of the traditional summer peak loads to justify the need for additional capacity makes the proposed transfer of Pleasants appear more favorable. Staff Init. Br. at 7. Staff notes that PJM is a summer-peaking entity, and if a capacity shortfall occurs in the winter, PJM will have plenty of cheap and available capacity for the Companies to acquire. Id. Staff

argues that fulfilling a winter capacity shortfall through the PJM markets makes more sense than acquiring a physical asset to satisfy a winter capacity shortfall. Id. Staff also questions whether adding a reserve margin to the winter peak is appropriate just because PJM requires enough capacity to meet its summer peak plus a reserve margin of approximately sixteen percent. A sixteen percent reserve margin in the summer means a much larger margin in the winter. At no time during the forecast period does the Companies' summer peak plus reserve margin drop below its winter peak. Staff Init. Br. at 7; also WVSUN/CAG Cr. Ex. 1. Staff recommends that the Commission determine load growth and capacity needs for the Companies based on the Companies' summer peak with the appropriate reserve margin which trends 250-350 MW lower than the winter peaks. Id. Staff also argues that the Companies' ratepayers will become unwilling market players, forced into unnecessary risks by decisions outside of their control. For this reason, Staff argues that the proposed transfer violates W. Va. Code §24-2-12. Staff Init. Br. at 8.

CAD also argued that the Companies inflated their projected capacity obligation by calculating their capacity needs based on winter peak load within the Companies' service territory. Like Staff, CAD contended that this is contrary to PJM rules which base future capacity needs on summer peak load. CAD noted that in a September 6, 2016 filing in Case No. 16-1074-E-P, the Companies asserted that they had a capacity surplus according to the most recent Base Residual Auction (BRA)<sup>12</sup> conducted for the 2019/2020 delivery year. CAD Init. Br. at 7. CAD witness Ms. Medine testified that "the Pleasants capacity exceeded the current deficit even with the sale of Bath County. Without this sale, it greatly exceeds the current deficit." CAD Init. Br. at 8; CAD Ex. ESM-D at 57. Mr. Gabel, the witness for Longview, concurred with Ms. Medine. Longview Ex. SG-D at 7.

CAD noted that FirstEnergy acknowledged in its most recent Form 10-K Report and in its July 2017 Earnings Call that over the past several years there has been a decrease in demand and excess generation supply in the PJM region that has resulted in an extended period of low power and capacity prices. CAD Init. Br. at 8-9 (citing FirstEnergy 10-K FY 2016 at 4 (2/21/17) available at <https://seekingalpha.com/filings/pdf/11872287.pdf>; FirstEnergy Q2 2017 Results – Earnings Call Transcript (7/23/17) available at <https://seekingalpha.com/article/4092032-firstenergy-fe-q2-2017-results-earnings-call-transcript>).

Longview also argued that the Companies do not need additional capacity. The Companies failed to follow the PJM formula which uses a summer peak analysis that accounts for winter needs within the region. Longview Ex. SG-D at 20. Additionally, Longview argued that the Companies based their projection of capacity need on anticipated economic growth in West Virginia that is not supported by the record.

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<sup>12</sup> PJM conducts an annual Base Residual Auction to procure capacity resource commitments needed to satisfy the PJM region's projected capacity needs for the Delivery Year, three years in the future from the auction date.

Longview Init. Br. at 3. Longview noted that the Companies failed to take into account the fact that PJM already considers load growth in the service area into their projections; therefore, the Companies essentially double-counted the localized, anticipated capacity need. Id.; Longview Ex. SG-D at 21-22. Longview also argued that the load forecast and fleet capacity as calculated by the Companies artificially exaggerates the difference between the forecasted capacity need and the Companies' generation capacity. Longview Ex. SG-D at 20.

#### **B. Pleasants as a Hedge**

The Companies contend that it is important for them to have a physical hedge against market volatility and cite to the Harrison Order and the IRP statute for support. Cos. Init. Br. at 2-3, 12-13.

The value of a physical hedge is that Mon Power has control over these high-load, high-price situations, rather than being at the mercy of the market when they occur. If Mon Power needs to purchase energy from the market during one of these situations to provide for the Companies' customers' needs, it has the benefit of also being able to sell into the market at the same high prices. This allows the revenues generated at the high prices to counter the high costs of supplying customer needs during the same periods. Without the physical hedge that capacity ownership provides, Mon Power must buy the high-priced energy to serve customer load but does not have corresponding revenues from its own market sales during the same periods. This leaves customers exposed – they end up paying for the difference in ENEC rates.

Cos. Ex. JAR-R at 12-13. The Companies note that WVEUG witness Stephen Baron also emphasized the nature and benefits of this hedge, differentiating the price protection the hedge provides from PJM's requirements that are intended to insure system reliability:

The Pleasants acquisition is really a physical hedge against the PJM market purchases that serve the Companies' customers. It is PJM's responsibility to insure adequate reliability in the APS zone in which the Companies operate; however, PJM does not provide any price protection to the Companies' customers that would mitigate the impact of higher PJM market capacity and energy prices. This is the role of Mon Power's owned and controlled capacity resources. By selling the output of these resources into the PJM capacity and energy market, and crediting the revenues in the ENEC, the Companies' owned capacity acts as a physical hedge to market purchases.

WVEUG Ex. SJB-D at 11. The Companies argue that these are some of the same considerations used in the Commission's approval of the Harrison acquisition. Cos. Init. Br. at 13.

### C. The RFP Process

The Companies were under no Commission or statutory requirement to issue an RFP and the failure to do so is not a violation of our rules. As the Commission has indicated in the past, the RFP process is not required, and it does not substitute for an in-depth Commission review of affiliated transactions under W.Va. Code §24-2-12.<sup>13</sup> We developed a complete record and subjected witnesses to cross-examination by the Parties and questions from the Commission. There was considerable comment and criticism of the Companies' use of the RFP process. The Companies argued that the RFP process was independent, unbiased and produced a fair result. The Companies suggested that several of the parties in this case have recommended an RFP process. In the Harrison case, Staff, CAD, WVCAG, Sierra Club and WVEUG all asserted that an RFP should have been used to identify the lowest cost resources to meet a capacity shortfall and to ascertain the fair market price of those resources. Cos. Init. Br. at 14. The Companies noted that in certain discovery responses some parties agreed that RFPs in general are valuable, but these same parties now argue that this RFP did not provide benefits.<sup>14</sup>

### D. Selecting Charles River Associates (CRA)

There was also considerable criticism by some parties about the selection of Charles River Associates (CRA). Some Intervenors argued that CRA should not have been selected for the critical assignment of developing and managing a fair and balanced bidding process.

Staff and CAD suggested that the hiring of CRA was suspect because CRA had millions of dollars in ongoing contracts with so many FirstEnergy affiliates that Mr. Lee could not identify them all. Tr. II at 98-99.

The Companies supported the selection of CRA. Mon Power pointed out that it initiated the RFP process by interviewing RFP provider candidates and selecting CRA to manage an independent RFP process. Cos. Init. Br. at 16. Mr. Ruberto and others

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<sup>13</sup> MP/PE had no legal obligation to issue an RFP prior to filing this case and the failure to issue an RFP does not constitute a violation of W.Va. Code §24-2-12. Harrison Order at 28.

<sup>14</sup> The Companies noted that WVSUN/CAG, Sierra Club, and CAD generally supported an RFP as a reasonable means for a load serving entity to identify the most cost-effective source of energy or capacity or both; helpful in demonstrating what options are available in the market; allowing a regulator to determine the costs and benefits of available options; helpful in establishing the reasonableness of a transaction; helpful in establishing the market value of the asset to be acquired; and helpful to assure that no undue advantage is afforded to RFP participants, including affiliates of the RFP issuer. Cos. Init. Br. at 15; citing JAR-R, Ex. JAR-1 at WVSUN/CAG discovery responses (DR) 6 and 7, Sierra Club DR 20, and CAD DR 18.

personally interviewed four potential RFP administrators to identify and select the most experienced, capable company to do the job. Id., citing Tr. I at 42-43. Mr. Ruberto recommended to Mon Power that it retain CRA and remained the principal contact with CRA throughout the RFP process. Tr. I at 47-49.

The Companies argued that CRA is well qualified and experienced in conducting IRPs. They explained that CRA had conducted dozens of competitive procurements on behalf of electric utilities and hundreds for clients across all industries. Cos. Ex. RJL-D at 2. Mon Power further explained that it had retained CRA and directed it to design an RFP that met all standards for fairness and insured no preference to any party. Cos. Ex. JAR-R at 15. The Companies contend that, other than expressing a preference for physical assets in the APS Zone because of PJM's rules on substituting units during critical hours, they entrusted CRA to design the RFP, identify potential bidders, administer the process, and evaluate the bids. The Companies provided testimony that CRA contacted twenty-eight potential sellers of capacity and demand response. CRA undertook bidder pre-qualifications screening and bidder "help line" administration and responded to bidder questions, with Mon Power input as necessary. RJL-D at 6-7. The Companies argued that Mr. Ruberto and CRA ensured that the RFP satisfied the FERC Ameren principles designed to determine whether an RFP process is fair and devoid of undue advantage or preference to affiliates. Cos. Init. Br. at 17. FERC has now ruled that Mon Power did not meet all of the Ameren principles in its FERC proceeding. Monongahela Power Co. and Allegheny Energy Supply Co., 162 FERC ¶ 61,015 (2018) at P 81 (issued January 12, 2018).

Staff, CAD and others asserted that CRA did not act as an independent third party, but rather as a clearing house for bids and a calculator of the cost of each bid to customers on a NPV basis. Staff asserted that the pertinent design criteria were decided by the Companies, not CRA. Staff Init. Br. at 11. CAD argued that the RFP gave undue advantage to AE Supply because Mon Power worked closely with CRA to establish the timing and scope of the RFP and the methodology that would be used to evaluate the bids. CAD Ex. ESM-D at 4.

Staff argued that the restrictive parameters placed on the RFP made it impossible for CRA to create a level playing field that did not favor the Companies' affiliates. Staff noted that Mr. Ruberto testified that he required CRA to seek bids from entities that could supply 1,300 MW of power from a physical generating asset in the APS Zone (Staff Init. Br. at 12; citing Tr. I at 45-46) and that CRA had no input into these limitations (id., citing Tr. II at 38-41, 43, 53-54, 56-60, and 63 (Lee testimony)). Additionally, Staff argued that Mr. Ruberto testified that he had ongoing discussions with CRA regarding the details of the RFP. Id., citing Tr. I at 55. Staff argued that those RFP conditions accomplished two goals: (i) ruling out the acquisition of power from any source other than a physical asset and (ii) essentially describing the Pleasants plant exactly. Staff Init. Br. at 12.

CAD argued that CRA also favored Pleasants by failing to consider the significant age difference in Pleasants and Longview. Pleasants is approximately thirty years older

than Longview and will have to be replaced sooner. CAD Init. Br. at 22. CAD also argued that the Companies failed to show a sound reason for limiting bids to the APS Zone. CAD Init. Br. at 23.

#### E. Preferences for Physical Generation Assets

In addition to the arguments that the criteria and conditions placed on the capacity proposal tilted the playing field in favor of the affiliated Pleasants plant, other criticisms were levied against the Mon Power preference for physical assets that it could purchase. HCP and BCP argued that Mon Power's refusal to consider a Power Purchase Agreement (PPA) was short-sighted because HCP and BCP could provide Mon Power with a PPA for capacity and/or energy that can be structured to be much less costly and with far lower risks to the Mon Power ratepayers than the purchase of Pleasants. HCP and BCP contend that with a PPA, Mon Power could manage power price volatility and offered their argument that structuring a PPA for capacity separate from a PPA for energy could be useful for the Companies because their capacity shortfall is far greater than their projected energy shortfall. They also argued that Mon Power would not have any up-front capital costs, maintenance costs or decommissioning costs. HCP/BCP Br. at 5 and 6.

In response to the criticism of requiring physical generation, the Companies argued that the preference for a physical asset was based in part on the 2015 IRP, in which Mon Power concluded that “[t]he lowest [cost] evaluated option to address Mon Power's needs appears to be the purchase of existing generating facilities. This option would require an agreement between Mon Power and any seller of the price that allows this option to remain the best solution.” Cos. Init. Br. at 17 (citing Monongahela Power Co. and The Potomac Edison Co., Case No. 15-2002-E-P, IRP filed 12/30/15 at 57).

The Companies stated on the record that PJM's new CP market design includes significant penalties to encourage performance by capacity resources during critical reliability events:

The failure to deliver energy during such events – referred to as “Performance Assessment Hours” – can result in penalties, and those could amount to more than a resource's yearly capacity revenue. Moreover, there are no meaningful exceptions that would excuse a capacity resource from such penalties. Therefore, it is critical that Mon Power have the operational flexibility to dispatch its capacity resources to meet these stringent Capacity Performance requirements. Accordingly, Mon Power decided to acquire fully-dispatchable capacity resources with reliable, year-round fuel supply availability and/or other operational characteristics to enhance reliability and availability.

Cos. Ex. JAR-D at 8-9.

The Companies argued that they had valid reasons to acquire a physical asset rather than power promised through a PPA. The 2015 IRP concluded that existing generation facilities likely would be the best option. Cos. Init. Br. at 18. Mr. Ruberto testified that owning an asset provides greater control over operations, maintenance, fuel procurement and capacity improvements, and a plant owner can modify facility operations to better suit market conditions and derive greater economic value from a facility – especially in the context of the operation of a fleet of assets within the same zone. Cos. Ex. JAR-D at 11; Tr. I at 68-73.

The Companies also argued that economies of scale arising from a larger fleet can reasonably be expected to help Pleasants, Fort Martin and Harrison operate more cost-effectively. Cos. Init. Br. at 18; Cos. Ex. JAR-D at 17, Tr. I at 68-75 (discussing the preference of owning a physical asset rather than purchasing power under a PPA). If contractual provisions are added to a PPA to address Mon Power's operational and control concerns, those provisions will affect Mon Power's cost and obligations. Cos. Ex. JAR-R at 17; Tr. I at 75. Mr. Ruberto testified that PPAs involve nonperformance, financial and bankruptcy risks if the terms of the PPA become unfavorable to the generator and the generator is unwilling or unable to continue operations. Cos. Ex. JAR-R at 18.

The Companies maintain that PJM rules effectively “allow a capacity resource to ‘net’ performance across multiple units, provided those units are located in the same PJM load zone.” Cos. Ex. JAR-D at 10, citing PJM Manual 18, Section 8.9. Resource performance during Performance Assessment Hours effectively can be netted from a performance risk management standpoint because PJM rules permit retroactive replacement of one resource’s under-performance with another resource’s over-performance if the resources are subject to the same Performance Assessment Hour. Cos. Ex. JAR-R at 18-19. Additionally, resources that over-perform during Performance Assessment Hours (PAH) have the opportunity to earn bonus payments. Cos. Ex. JAR-R at 19. For example, if a PAH occurs in the APS Zone, the risk that one unit may under-perform can be hedged by having other units with the ability to over-perform and collect bonus payments. The Companies acknowledged that although these bonuses were unlikely to offset penalties on a one-on-one basis, they are still a valuable hedge against CP penalty risk.

#### F. ABB Pricing and NPV Analyses

The Companies noted that the CRA evaluation and calculation of the costs and NPV of total costs of the various bids utilized forecast inputs from an established and independent provider, ABB. Companies testified that “[i]n the Spring and Fall of each year, ABB develops electricity, fuel, and environmental price forecasts for its North American Power Reference Case covering 73 market areas.” Cos. Ex. TS-D at 3.

The Companies argued that CRA administered the RFP fairly and provided no undue advantage to any RFP participant. The Companies argued that the one-week

prequalification period, beginning December 16, 2016, and ending December 23, 2016, was sufficient in light of the direct notification that CRA provided to resource owners and the perfunctory information the prequalification required. Cos. Init. Br. at 21. The Companies also noted that one entity that missed the prequalification date was still permitted to submit a bid. Tr. I at 234. Mr. Lee testified for the Companies that the seven-week period for RFP responses was consistent with capacity resource RFPs for other utilities and no bidders expressed any concerns about the timeline being a barrier to participation. Cos. Ex. RJL-R at 3-4; Tr. II at 51. Criticism of the scoring process was unpersuasive, according to the Companies, because the information provided to potential bidders about the valuation and scoring was consistent with industry practice in competitive solicitations. Cos. Init. Br. at 22. Sophisticated parties contemplating participation in an RFP of this type generally know that there are many different factors to be weighed in evaluating dissimilar assets. Id.; Cos. Ex. RJL-D, attachment 1 at section 4.

The ABB projections used by CRA and calculation of NPV were disputed by other parties. Longview Power witness Steven Gabel argued that the Companies greatly overstated their ability to sell extra capacity into the wholesale market at a profit. He noted that the BRA for DY 2020/2021 was held in May 2017 and capacity prices cleared at just \$76.53 per MW-day compared to ABB's forecast of \$148.92 per MW-day. Longview Ex. SG-D at 7-8; Cos. Init. Br. at 27.

CAD argued that CRA had available, and should have used, a more recent ABB price forecast. CAD Init. Br. at 24. CAD also stated its belief that in addition to the ABB capacity price forecast conflicting with market reality, it conflicted with views publicly expressed by FirstEnergy. CAD contended that during an earnings call regarding the results of the third quarter of 2016, a FirstEnergy representative stated that PJM's competitive market conditions continued to deteriorate, punctuated by weak power prices, insufficient results from recent capacity auctions and anemic demand forecasts and that these conditions led the company to announce that it would expeditiously move away from Competitive markets – a plan which included the proposed sale of Pleasants to Mon Power. CAD Init. Br. at 11, citing FirstEnergy Third Quarter Earnings Call transcript, November 4, 2016.

HCP and BCP argued that new state-of-the-art natural gas plants have much greater operational flexibility and can run efficiently as baseload plants or quickly change energy production levels to respond to changing load conditions on the grid if called to do so. HCP/BCP Br. at 4. HCP/BCP witness Andrew Dorn stated that when asked to fluctuate output based on grid conditions, coal plants experience more wear and tear than the new state-of-the-art gas plants that were designed with operation flexibility in mind. This, they contend, reduces the useful life of the equipment and significantly increases maintenance costs. HCP/BCP Ex. AWD-D at 4.

## G. Cost of Pleasants Relative to Other Proposals Received and NPV Analysis of Pleasants Relative to the PJM Market

Mr. Lee testified for the Companies' that CRA's dispatch model was appropriate. Multiple dispatch models are available for industry use and one is not necessarily superior to another. Cos. Ex. RJL-R at 17. CRA's dispatch model was tailored to the purpose of its analysis – to compare the relative economics of each of the plants bid into the RFP under consistent market conditions. *Id.* at 18. The Companies' witness testified that integrated market modeling, as described by Ms. Medine, CAD's witness, would have added significant cost, but little incremental benefit.

When we developed the RFP process, we did not know how many bids we would receive or the location of each of the facilities offered. Calibrating the model inputs and assumptions to ensure a reasonable capacity balance would have been time consuming and costly, and the primary purpose of the calibration would have been to generate reasonable market prices for power – essentially the same data as was provided by ABB. Like the CRA dispatch model, these integrated models require input assumptions that are typically derived from third-party forecasts. Integrated models do not somehow eliminate questions related to forecast accuracy, and in the context of a comparative evaluation of bids in an RFP, they increase concerns about forecast consistency.

Cos. Ex. RJL-R at 19. The Companies also argue that Ms. Medine did not present an integrated market model as a part of her testimony, address any of the problems outlined above or show that using a different model would have made any difference. Cos. Init. Br. at 24.

The Companies further assert that there is also no single industry-accepted customer impact period to be used in an NPV analysis. *Id.* at 25. Mr. Lee selected a fifteen-year period because it was long enough "to understand the relative economics of the competing bids," allowing projected facility operations to reach a steady, long-term state under the forecasted market conditions. Cos. Ex. RJL-R at 8-9. The Companies argue that beyond this period, assumptions about performance factors become much more speculative as they move into the future, and cost factors have a comparatively small impact on the NPV because of discounting. Cos. Init. Br. at 25. Additionally, even if a longer period, such as twenty years, had been used, according to the Companies, the difference in the NPV positions for the bids would not have been materially different because the Pleasants NPV per kW unforced capacity (UCAP) was far higher than its RFP competitors. Cos. Ex. RJL-D, Ex. RJL-1 at Table 2.1.

To run the NPV analysis, CRA needed a set of natural gas, energy and capacity prices. ABB is a respected, independent source of market forecasts, and no one claimed that ABB's approach is biased toward or against any market outcome. When ABB

prepared the Spring 2016 Reference Case, neither ABB nor CRA could have known that CRA would later use those forecasts in a Mon Power RFP. Cos. Init. Br. at 25-26.

Mr. Sweet testified for the Companies that historically low natural gas prices cannot be expected for the foreseeable future based on ABB fundamentals-based modeling. ABB considers market fundamentals such as projected production levels, the relationship between current prices and sustained growth over the long term, debt levels of U.S. oil and gas exploration and production companies, and the likelihood that higher intensity techniques will be needed causing diminishing returns to scale. Cos. Ex. TS-R at 3-4. Mr. Sweet noted that ABB considers gas infrastructure projects in its forecasting, including construction costs and pipeline reservation rates that were not considered by other witnesses, such as Mr. Schlissel and Mr. Comings. Cos. Init. Br. at 27; Cos. Ex. TS-R at 9-10. The Companies argue that criticism of ABB's capacity price projections were clearly hindsight-based and centered on a single data point: a divergence between the actual RPM clearing price for DY 2020-21 (approximately \$77/MW day) from the May 2017 BRA and ABB's forecasted price of \$149/MW day, that was projected in the spring of 2016, prior to the May 2016 auction. Cos. Init. Br. at 27. The Companies argue that the capacity price projections made by Mr. Schlissel and Mr. Comings are suspect on their face because they forecast capacity prices in the out years (DY 2028-29 through 2032-33) at levels no higher than the price range prevailing in the last six auctions (roughly between \$100 and \$160 per MW day). Cos. Cross Ex. 7.

The Companies also contend that CRA's plant performance and cost assumptions were valid. Mr. Lee's discussion of CRA's capacity factors stressed that they were outputs of the modeling, not inputs based on recent observed performance. Cos. Ex. RJL-R at 25-26 and Figure 2. Mr. Lee explained that capacity factors for baseload plants typically are not the most important factor related to plant profitability in the energy market:

Plants in organized markets tend to earn a large portion of their energy market profits during a relatively small number of high-priced hours. In many operating hours, plants' marginal costs are close to their energy market revenues, meaning that whether the plant is running or not would not have a significant profitability impact. As a result, a small deviation in operating cost assumptions may have a dramatic impact on estimated capacity factors but very little impact on overall margins.

Id. at 27-28 and Figure 3 (showing that eliminating twenty percent of the dispatch hours only reduced two percent or less of the energy margins earned by the facility over the course of the year).

Mr. Lee also criticized the rationale offered by Longview witnesses Mr. Gabel and Mr. Kumar that CRA should have favored industry-wide performance averages or costs at other similar facilities over costs derived from actual operating performance of the facility in question. Mr. Lee notes that operating costs at power plants are not uniform

and substituting item-level costs from one facility into cash flow estimates of another facility “creates risk of double counting or missing certain cash flows due to classification inconsistencies” and thus misses true plant-level variations in data. Cos. Ex. RJL-R at 15-16.

Mr. Lee testified that a series of scenario analyses taking into account a range of price assumptions would not have altered the relative economics of the NPV analysis for each of the proposals received because there are “infinite numbers of potential scenarios for domestic power markets,” and it would have been unrealistic and unnecessary to model every possible scenario. Cos. Ex. RJL-R at 24-25. He also testified that additional scenarios would have complicated the bid evaluation by requiring CRA to develop a complicated set of rules for evaluating each bid under a set of multiple NPV values. Id. The Companies note that Mr. Eads, witness for Staff, ran thirty scenarios using a range of forecasted information and assumptions, after making adjustments to capital investment, capacity factor, heat rate, fixed O&M expenses, and depreciable life, and twenty-five of the thirty scenarios still projected a positive NPV. Staff Ex. TRE-D at 6-10 and attachment 1.

Furthermore, the Companies argued that CRA appropriately excluded costs that would have been either improper to consider in a fifteen-year analysis or were too uncertain to be included. Cos. Init. Br. at 31.

The Companies argued that the CRA correctly addressed the in-state fuel consumption factor. The in-state fuel factor in the RFP scoring would not have materially affected the RFP outcome, no matter what scores Pleasants and Longview received on it. Cos. Init. Br. at 32. The Companies noted that Pleasants is currently sourcing over eighty percent of its coal from West Virginia while Longview sourced all or nearly all of its coal from Pennsylvania. Additionally, the Companies argued that the Longview proposal did not provide any detail on costs associated with potential sourcing of fuel from within West Virginia. Id. at 33.

Staff argued that if the Commission determines that the Companies have a need for additional capacity and the RFP process was not so flawed as to render it useless, the Commission must then determine whether the acquisition of the Pleasants Plant is the best and most appropriate solution. Staff Init. Br. at 13. Mr. Eads developed an NPV analysis that began with the CRA analysis which relied on the ABB market forecast. Mr. Eads then made adjustments that he felt more accurately reflected the likely operation of the three conforming bidders. The impact of the adjustments was to lower the NPV of Pleasants from the \$696 million calculated by CRA to \$356 million. The adjustments also slightly improved the NPV of the combined-cycle gas plant and slightly lowered the NPV of Longview. Staff Ex. TRE-D at 11.

Mr. Eads also modeled a number of scenarios using his numbers related to the operation of the three plants and substituted those numbers into several PJM market forecasts from ABB, AEP and Navigant. Under his analysis, Pleasants was the clear

winner. Staff Ex. TRE-D at 24-25. Mr. Eads then used an average of the CRA/ABB forecast and the AEP Mid-Band forecast in an effort to provide a balanced approach between the multiple market forecasts. Under this analysis, the Pleasants acquisition has an NPV of a positive \$278.4 million. Id. at 28-30.

After comparing the cost of Pleasants to projected market costs, Mr. Eads indicated that although Pleasants showed a positive result compared to the market, the amount of the benefit, in his opinion, was not significant enough versus the risks associated with owning Pleasants for him to unequivocally recommend the Pleasants Transaction.<sup>15</sup> The risks included the potential of acquiring too much capacity, selecting the wrong type of capacity, selecting a generating source that requires a more expensive fuel source, unanticipated environmental costs related to the fuel source, fuel supply disruptions, obsolescence causing premature retirement and price volatility. Staff Ex. TRE-D at 35. Mr. Eads further testified that purchasing needs from the marketplace could avoid some of those concerns. Staff Ex. TRE-D at 36.

#### H. Value and Condition of Pleasants

The Companies note the relatively low price for Pleasants of \$150/kW. Cos. Init. Br. at 35. The Companies argue that the Pleasants purchase price is market-derived, lower than other bids, and very low when compared with other West Virginia power plant net book values in recent transactions. Cos. Init. Br. at 33. The Companies also argue that an impairment analysis, as suggested by Mr. Baron, witness for WVEUG, is essentially an appraisal of an asset's value made necessary when there is no actual market value available. The Companies contend that using a competitive RFP process resulted in a presumptively valid, market-derived price. Id. The Companies argue that asset sales in PJM West, as referenced by Ms. Medine and Mr. Schlissel, were not reliable bases for determining Pleasants' fair market value because there was no evidence that these situations were comparable to Pleasants. Cos. Init. Br. at 34. The Companies suggest that the 2013 Pleasants transaction and the 2013 Harrison transaction at \$733/kW and \$565/kW respectively, offer more constructive guidance on the current value of Pleasants. Cos. Init. Br. at 34-35, citing Harrison Order at 14 and Exhibit B, p. 7 of Appendix A.

Mr. Ruberto testified that FirstEnergy's decision to leave the competitive generation business should not be the basis to determine Pleasants' projected profitability and market value. Cos. Init. Br. at 35. Mr. Ruberto testified:

The difference in value that a buyer and a seller assign to a particular asset is the basis of all market exchanges. Buyers and sellers have different

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<sup>15</sup> "While \$278 million is a decent benefit, it would only take a few additional years of lower than expected PJM Market prices, or a jump in coal prices, to reduce the benefit to near or below zero and result in a net increase in customer rates during the initial years. This being the case, I am torn between Pleasants and the PJM Market." Staff Ex. TRE-D at 36.

economic circumstances and different needs. Mon Power is a vertically integrated utility that has a need for capacity to serve its customers and the customer of PE-WV. Mon Power's cost of capital and its operational and financial priorities are likely to differ from those of entities that are not vertically integrated utilities.

Cos. Ex. JAR-R at 36. There is no reason to believe that AE Supply has the same costs of debt and equity capital that the Companies have, or that its investment horizon and investment priorities are the same as the Companies' priorities. Cos. Init. Br. at 36.

The Companies further contend that Pleasants is a valuable asset with many years of service life ahead of it. It is a well-maintained, modernized facility. *Id.* at 37. Mr. Evans testified that the preventive maintenance program used by the facility is modeled from the Electric Power Research Institute. Tr. II at 370-71. Pleasants inspects critical equipment, such as transformers, to ensure reliability and prepare for high-impact, low-probability events. *Id.* at 368. Pleasants conducts scheduled outages on each unit every three years and performs replacements as necessary. *Id.* at 348. These practices have allowed Pleasants to operate efficiently and prolong its useful life. Cos. Init. Br. at 38. Additionally, Pleasants has ensured its viability through strategic capital investments, including replacement of boiler components and distributed control systems. It is also in compliance with environmental rules. Cos. Ex. DE-R at 3-4.

The Companies also obtained an independent evaluation of Pleasants by Black & Veatch, a recognized industry expert. Cos. Init. Br. at 39. Black & Veatch concluded that:

[T]he facility is well-maintained and capable of providing reliable service for many years. It currently has few operating limitations and despite its nearly 40 year age has reasonable costs related to operation and maintenance which appear to be very effective in maintaining efficiency, reliability and availability levels in line with those represented in the response.

Cos. Ex. KPL-D at attachment KPL-1, §1.1. Mr. Leutheuser, who managed the review of Pleasants for Black & Veatch, testified that the various capital projects undertaken at Pleasants over the years "demonstrate an ongoing modernization of the plant that addresses operating problems and regulatory compliance." Cos. Ex. KPL-R at 3.

The Companies argue that the plant will provide significant customer benefits including (i) capacity deficiency for the Companies will be covered through 2027 based on current load forecasts, (ii) the acquisition will provide a physical hedge against volatile market prices, (iii) the opportunity for net revenues from generation sales will serve as direct offsets to ENEC costs, and (iv) an enhancement of Mon Power's asset base and overall capitalization could benefit customers through more favorable financing terms. Cos. Init. Br. at 41. Further, the Companies argued that the transfer will permit an

overall reduction in customer rates as the projected ENEC rate reduction will more than offset the impact of the Temporary Surcharge. Cos. Ex. HCK-D at 9-10.

The Companies also argue that the Transaction will benefit the State of West Virginia. Approving the transfer and maintaining plant operations will preserve hundreds of jobs at the plant, in mining, and in other supporting businesses that would positively impact the State's economy. Cos. Init. Br. at 42.

Staff witness Walker noted some areas of concern with the condition of the boilers. Staff Ex. DEW-D at 5, 8-11. Additionally, he expressed concern that Pleasants is forty years old and, when built, had a life expectancy of forty years. Staff noted that it is possible the plant may operate for another twenty years, but there could be high maintenance costs, multiple outages and load curtailments. *Id.* at 13.

Although the Companies plan to depreciate the Pleasants plant over twenty-seven years, because of the age of the plant and other unknown circumstances, the plant could close prematurely if Pleasants becomes uneconomic to operate or faces environmental restraints that cause it to close. If this occurs, Staff argues that ratepayers would still be responsible for the undepreciated rate base. This risk would not be present with a PPA or reliance on the market. Staff Init. Br. at 21.

HCP/BCP witness Dorn testified that the lack of gas plants in West Virginia, as opposed to the development and construction of numerous new combined-cycle natural gas power plants in Ohio and Pennsylvania, is because of the regulatory climate in West Virginia.<sup>16</sup> Mr. Dorn testified that granting this Transaction could jeopardize future investment in gas plants in the State because it may be viewed by financial markets as an irrational uneconomic state-level subsidy. Approval of the deal would send a signal to the financial markets that West Virginia has a high degree of regulatory uncertainty, and it would discourage significant capital investments in West Virginia when neighboring states with access to the same gas and power markets have proven regulatory track records for approval of construction of natural gas power plants. HCP/BCP Ex. AWD-D at 6-7; HCP/BCP Init. Br. at 8.

CAD contested the value of Pleasants as a modernized facility. The Pleasants facility is old. Longview witness Burnett indicated that his analysis of the historical operating hours, capital expenditures, operations and maintenance budgets, outage data and other information available to the Parties does not clearly identify what maintenance has been performed over the years to justify characterizing Pleasants as a modern plant that will be reliable for another twenty years. Longview Ex. TB-D at 9. Mr. Burnett noted recent equipment failures and significant maintenance to ensure reasonable reliability of the plant. Mr. Burnett suggests that these maintenance efforts and costs will

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<sup>16</sup> In response to questions from the Commission, Mr. Dorn agreed that there had been no delays in the processing of siting certificates for two gas-fired power plants under development by his Company and that two such plants had been certificated and one was on track for Commission action. Tr. II at 34.

increase because the plant operations and the majority of the equipment are still original and have not been changed. Longview Ex. TB-D at 32-33. Staff witness Walker noted that the finishing superheater for the Unit One boiler was replaced with a less tolerant steel in 2010 and the boiler is currently experiencing tube failures because of the material. Staff Ex. DEW-D at 9. Mr. Walker testified that the original boiler tubes were at the end of their life expectancy of forty years and a rough estimate for the replacement of the boiler tubes in the finishing superheater would be approximately \$9 million per unit. Staff Ex. DEW-D at 10. Dale Evans, Technical Services Manager at the Pleasants Plant, testified that the plant was continually evaluating plant components and performing life-extension or capital replacements when and where necessary. Cos. Ex. DE-R at 2. Mr. Evans specifically refuted that the boilers were problematic, stating instead that they are in good shape and could last for many years. Id. at 10.

CAD witness, Ms. Medine, testified that the certain coal supplies assigned to Pleasants are above-market by almost \$13 per ton. She described this as problematic for two reasons. First, she argued that capacity and energy market prices have been low and that Pleasants' ability to dispatch could be impaired by having an above-market price contract for coal. Second, she noted that the Companies will be asking for recovery of fuel costs through the ENEC and the above-market coal pricing increases the price ratepayers will be paying for power. CAD Ex. ESM-D at 36.

CAD Init. Br. at 15-16; CAD Ex. ESM-D at 33-35, 37.

Staff witness, Mr. Short, testified that, as West Virginia utilities have continued to rely primarily on coal-fired generation over the last ten years, the average retail price of electricity in West Virginia has increased 77.5 percent. In contrast, the average retail price of electricity in the United States has increased by only 15.6 percent with a move from predominantly coal to natural gas. Staff Ex. RRS-D at 10.<sup>17</sup>

Mr. Burnett and Mr. Kumar testified that, although they had made no examination of Pleasants, a more thorough engineering and operations review was warranted to fully analyze the historical spending at the plant and to best determine a realistic view of anticipated future needed expense. Longview Exs. TB-D at 25 and NK-D at 43. Mr. Burnett testified that the plant's major components will continue to have failures. Longview Ex. TB-D at 16.

Mr. Kumar testified that the number of hours Pleasants operates at lower load (cycling) is increasing. Longview Ex. NK-D at 25-26; Tr. III at 256. Also, the Black and

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<sup>17</sup> The Commission notes that the percentages quoted may appear to show increases in West Virginia that are five times greater than the national average. The rates in West Virginia were much lower than the national average ten years ago, so the percentage increases calculated on the lower West Virginia rates, as a percentage, appear severe. Looking at the absolute increase, however, the average West Virginia rate has increased by around 3.5 cents per kWh, or just over two times the national average increase of 1.6 cents per kWh. Even with the larger absolute increase, West Virginia electric rates are still below the national average.

Veatch report, relied upon by the Companies as an engineering assessment, did not address the risks of a high-impact, low-probability (HILP) event. Mr. Kumar testified that older units have a much higher chance of experiencing HILP-related forced outages. Longview Ex. NK-D at 36-37.

### I. The McElroy's Run Impoundment and Dam

According to Companies, McElroy's Run Impoundment and the associated dam (McElroy's Run Impoundment and Dam) is safe and structurally sound and is needed for operations. The impoundment has operated without incident since the inception of the plant. Cos. Init. Br. at 39. McElroy's Run has a confirmed 10.67 years of storage space and operation in the facility. Tr. II (Evans Testimony) at 341. The Companies acknowledge that the impoundment is classified by the U.S. Army Corps of Engineers classification system as a "high hazard." Mr. Evans, however, explained that this classification is not indicative of the operational condition or safety of the impoundment, but merely means that if such a dam was to fail, loss of human life would likely occur – an unlikely outcome since the Pleasants site encompasses the impoundment, which has a maximum water depth of four feet, and all of that land is between the impoundment and the Ohio River. Tr. II at 81, Tr. III at 308, and Tr. IV at 30-31. Staff witness Dove visited the impoundment site and testified that he believed it was in good condition. Staff Ex. DWD-D at 32.

Mr. Evans, Technical Services Manager for Pleasants, in discussing generally the environmental record of the station, stated:

We are in compliance and, in fact, we --- we went over three years without any reportable environmental occurrence at that station. Our safety record is just as good and we have gone over three years --- we went over three years without a reportable safety incident at that station.

Evans, Tr. II at 364.

Mr. Dove testified that the estimated closure and post-closure costs for the impoundment are approximately \$43.8 million. This estimate was not based on the preparation or review of a closure plan for the McElroy's Run Impoundment, but was estimated based on the bond requirement on a similar impoundment in Pennsylvania.<sup>18</sup> Mr. Dove used a similar methodology to arrive at an estimated \$21.8 million

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<sup>18</sup> Mr. Dove examined the closure plan for The Little Blue Run (LBR) Disposal Area adjacent to the FirstEnergy Bruce Mansfield Plant in Pennsylvania. He determined that plan was similar to the closure/ post-closure plan for the McElroy's Impoundment. He simply divided the estimated bond amount for the LBR Disposal Area of \$162,272,180 by the total number of LBR acres (936 acres) to arrive at an estimated cost of \$173,368 per acre for closure/post-closure costs. He then applied this cost to the 253 acre McElroy's Run footprint to arrive at the closure/post-closure cost estimate of \$43.8 million.

closure/post-closure cost for the Pleasants landfill. Staff Ex. DWD-D at 29. According to Mr. Dove, ratepayers would have to pay these costs.

Staff argued that the potential liabilities associated with the ownership of the impoundment are unknown. Staff witness Dove testified that the Tennessee Valley Authority was recently required to line an impoundment, not because of current problems, but because of the likelihood of future problems. A similar order for the Pleasants plant, if ever issued, would increase the costs of the impoundment. Staff Ex. DWD-D at 32-33. Staff argued that the impoundment should not be transferred if it will not be used and useful because of the high closure costs (approximately \$43 million) and limited amount of volume left in the impoundment. Tr. IV at 35-39, 41.

#### J. Risk Sharing

The Companies argue that if the transfer occurs, the costs and subsequent market operation of Pleasants should be governed by the same regulatory framework for cost recovery that governs all of Mon Power's other generating units. Cos. Init. Br. at 44. West Virginia rate regulation is based on the cost-of-service model with fuel and purchased power costs reconciled and recovered through the ENEC. *Id.* The Companies contend that their Fort Martin and Harrison Power Stations are subject to cost-of-service based rate regulation, even though 100 percent of the market risk attendant to their operations is borne by customers, and there is no certainty that they will produce a net NPV benefit for customers over their service lives. *Id.* The Companies distinguish the acquisition premium in Harrison from the proposed risk assignment in this case. Cos. Init. Br. at 44-45.

The Companies argue that the proposed risk assignment is contrary to the legal rate structure and regulatory paradigm in West Virginia that a utility recovers its costs for assets deemed prudent and has an opportunity to earn a fair return on that asset. *Id.* at 45. The Companies assert that some intervenors want to shift market risk to the utility without providing the higher cost of debt and higher cost of equity that would normally occur for an entity that is exposed to the market. *Id.* The Staff, WVEUG, and WVSUN/CAG risk-sharing proposals are also unwarranted because they use the PJM market as a benchmark for the Companies' entitlement to cost recovery. *Id.* at 46. Companies argue that these intervenor proposals do not represent a fair allocation of market benefits and risks.

Mr. Eads testified that the Staff Utilities Division would support the purchase of Pleasants if the ratepayers were shielded from the risks discussed in the NPV Analysis section above. Staff Ex. TRE-D at 35-36. If the market experienced a few years of lower-than-expected PJM market prices or a jump in coal prices, the Pleasants Transaction would be a negative asset. For example, Pleasants would have a negative \$234 million NPV using the AEP low band market forecast. Staff Ex. TRE-D at 36. Staff contended that most analysts would agree that the cost of natural gas is currently driving prices in the PJM region.

Staff witness deGruyter, the Commission gas industry witness, stated his belief that natural gas prices will remain essentially flat for the next five to ten years. Staff Ex. EFD-D at 5-6; Tr. IV at 15. Mr. deGruyter stated that he believed assumptions about rising natural gas costs due to the development of multiple intrastate natural gas pipelines are incorrect. He testified that “the general feeling in the industry” is that when the pipelines are completed, more wells will be drilled and more gas will be available for market, thereby keeping downward pressure on prices. Staff Ex. EFD-D at 5-6; Tr. IV at 17. Staff argued that if these assumptions about gas prices are correct, the alleged benefit to ratepayers in the near- and mid-term could be diminished because the majority of the projected revenue comes through the energy market. Staff Init. Br. at 18. Additionally, there is a risk of higher-than-expected coal prices that could come about as the supply of coal becomes short as more and more coal mines shut down and the risk of the plant not being able to physically perform at expected levels because of aging equipment which could affect the plant’s revenues. Id.

Staff said that the ratepayers should be shielded from the risk of owning Pleasants versus reliance on the market through a mechanism that limits ratepayer exposure to the lower of market costs versus the costs of owning Pleasants. Staff Ex. RRS-D at 15-17. This risk sharing proposal would benefit the Companies by allowing them to share in projected additional revenues. Staff Init. Br. at 25. Staff argued that, given the recent generation transactions, the Commission should condition approval on some sort of market risk sharing mechanism. Staff Init. Br. at 26.

Staff testified that another condition to protect ratepayers from unnecessary risk is the exclusion of the impoundment from the Transaction. Mr. Dove testified that the Companies should not take on the impoundment unless it is essential to the operation of the plant. Staff Ex. DWD-D at 35. Mr. Evans testified for the Companies that in the future, the plant would change entirely to a dry impoundment operation by installing the best available technology at that point. Cos. Ex. DE-D at 12. Furthermore, the impoundment is approximately ninety-four percent full. If the Companies acquire the Impoundment, they should only be liable for six percent of the costs of the impoundment. Staff Init. Br. at 27. Additionally, an indemnification agreement like the one ordered in the Mitchell transaction, Case No. 14-0546-E-PC, should be required. Id.

Staff also recommended rate protection as described in the testimony of Mr. Oxley, including denying the proposed true-up for the surcharge proposed by the Companies. The Commission has not traditionally allowed for the true-up of these types of costs that are generally under the utility’s control, with the exception of the Harrison case in which the Commission approved a settlement that included a true-up. Mr. Oxley also recommended that the requested return on equity (ROE) be adjusted to 9.75 percent because that represents the most recent allowed ROE in a litigated rate case. Further, Mr. Oxley recommended that the proposed rate decrease not be fully implemented in case the Companies’ calculations are incorrect. Staff Ex. ELO-D at 8-12; Staff Init. Br. at 28.

#### K. Possible Delay of the Transfer

The Companies argue that a possible conditional approval that would require delaying for a period of time the closing on the Transaction to await subsequent market results is infeasible and unwise for a variety of reasons. AE Supply may not wait the prescribed amount of delay time and may instead look for another buyer, close the Pleasants plant or sell the plant for a higher price. Cos. Init. Br. at 49-50. A delay would jeopardize the benefits of the transfer, and there is no guarantee that the issues in the regulatory and market landscape for generators in PJM would be resolved. *Id.* at 50.

Staff supports the proposed review period. Alternatively, Staff suggested that the Companies be required to issue a new, more inclusive and robust RFP. A new RFP would allow some time to see if the Companies' projections are correct and a fuller RFP would allow the entire marketplace to speak for itself. Staff Init. Br. at 29.

#### L. Temporary Surcharge and Ratemaking

The Companies testify that cost recovery is necessary, and the incremental costs normally recovered in base rates should be recovered immediately through a surcharge (Temporary Surcharge). The Companies propose that the Temporary Surcharge be trued-up to reflect changes in base costs until their next base rate case. The Companies also argue that a ten percent return on equity is more reasonable than proposals by other parties and the Commission should use the ten percent ROE for the limited duration of the Temporary Surcharge. Cos. Ex. REV-D at 11-12; Cos. Ex. REV-R at 5-6; Cos. Init. Br. at 52.

Staff did not oppose the Temporary Surcharge but did oppose the annual true-up mechanism and the return on equity used by the Companies in calculating the temporary surcharge. Staff argued that the true-up mechanism was an unusual departure from base rate establishment of revenue requirements and cited Commission Orders involving acquisition of generation plants by Appalachian Power Company and Wheeling Power Company where the Commission denied a true-up mechanism. Staff Ex. ELO-D at 5-10.

WVEUG opposed the Temporary Surcharge. Instead, WVEUG recommended a deferral of the fixed, base rate cost components of Pleasants' ownership and operations and a future cost recovery determination by the Commission in a base rate case. The WVEUG witness testified that industrial customers were already paying rates that exceeded their reasonably allocated revenue requirements and that class cost allocation should be resolved along with a determination of the allocation of the base rate cost components related to Pleasants. WVEUG Ex. SJB-D at 33.

## **VI. DISCUSSION**

We listened to the testimony of the witnesses, read pre-filed material, exhibits and briefs, and reviewed the issues in this case. Although there was a massive amount of

both prefiled and hearing testimony, we are troubled by what we perceive the lack of hard financial analyses, with the exception of Staff witness Eads. It is difficult to participate in the hearings, review the enormous record in this proceeding and not conclude that, to large degree, the proceeding and the positions of the parties can be fairly summarized as dueling experts on the issues of each party in the case. The Discussion of the Issues in this Order evidences the stark contrast between the parties, but much of that contrast is in the nature of “did too” and “did not” statements by expert witnesses, contesting what the Companies did and why they did it. There may be nothing wrong with that, but in the final analysis, we do not attempt to balance or assess the oscillating scales of justice based on which side presents the most expert witnesses.<sup>19</sup>

We also do not intend to repeat the foregoing discussion of the issues set forth in this Order, but we have considered those matters extensively and believe that the following observations about this case are appropriate.

#### A. Pleasants Transaction is not the Harrison Power Transaction

Various efforts, both directly at public comment hearings,<sup>20</sup> and obliquely through news stories, have been made attempting to equate the proposed acquisition of Pleasants to the Commission’s approval of the acquisition by the Companies of a 79.46 percent ownership interest held by AE Supply in the Harrison Power Station. The Companies attempt to find support in the Commission’s Harrison Order for owning generation capacity, disregarding the different facts and circumstances of the Harrison case from this case. In substance, the Companies argue that the Commission approved the Harrison transaction and should therefore approve Pleasants as well. Cos. Init. Br. at 6-8.

The Companies’ reliance on Harrison to support the Pleasants Transaction is misplaced. The facts and circumstances facing the Companies’ capacity and energy needs at the time of the Harrison transaction were not at all close to the facts and circumstances regarding capacity and energy needs presented in the record in this case.

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<sup>19</sup> That is so even where, as asserted by the Sierra Club, a “diverse assemblage of groups” have united to oppose the transaction:

With its proposal to purchase the Pleasants Power Station, Mon Power has managed to unite a diverse assemblage of groups that represent widely differing viewpoints. Environmental groups, renewable energy advocates, large industrial energy users, residential customers, power-plant owners, citizen watch-dogs, and even the Commission’s own staff have come together with a single-coherent message: *the proposed purchase of the Pleasants plant is bad for West Virginia.*

Sierra Club Opening Br. at 1 (emphasis in original).

<sup>20</sup> This includes public comment such as that of Mr. Craig, commenting at the Martinsburg public comment hearing that the Harrison Plant cost customers more than \$160 million according to the Institute for Energy Economics and Financial Analysis. Martinsburg Tr. at 58.

The Harrison transaction was approved based on the state of the facts and law in 2013/2014. The record in the Harrison case demonstrated that the Companies were facing a summer capacity shortfall; that is not a fact supported by the record in this case. We further remind the Companies that the record in the Harrison case demonstrated that the Companies were facing a significant shortfall in meeting their energy requirements with internal generation resources. That is not a fact supported by the record in this case.

Just as the Companies are wrong in trying to justify an approval of the Pleasants Transaction on the Harrison acquisition approval, so too are the attempts of some of the opposing parties who imply, without the benefit of evidence, that the Harrison acquisition was a bad decision.

Without any evidence regarding the actual and projected impact on customers due to the Harrison transaction, before and after any adjustments due to the conditions placed on full Harrison cost recovery, some parties who oppose Pleasants condemn the Harrison transaction and by association hope to cast doubt on the Pleasants Transaction. Staff Init. Br. at 2.

Those parties who oppose the Pleasants Transaction because they believe that the Harrison transaction was an unwise decision should remember that the Harrison acquisition was supported by the facts and circumstances in 2013/2014. We further remind those parties that they did not present any evidence in this proceeding that there are any long-term or continuing detriments to customers attributable to the Harrison transaction. Unsupported papers or newspaper opinion pieces that ignore the potential for future rate adjustments associated with the conditions imposed by the Commission in this Pleasants decision that were never entered into the record in any Commission proceeding, that were never subject to examination by any party or the Commission, and that were never subject to rebuttal are not evidence that could conceivably support any findings of fact or conclusions of law that must underpin legally defensible Commission decisions.

Finally, we remind the parties that the Companies; the Staff; CAD; WVEUG; Utilities Workers Union of America (UWUA); the Sierra Club; the West Virginia State Buildings and Trade Council, AFL-CIO; WVCA and Utilities Workers Union of America, AFL-CIO, and its Local 304, all joined in the Harrison Joint Stipulation and recommended to the Commission that the Commission approve the Harrison transaction based on that Stipulation. Even then the Commission placed certain conditions on the full recovery of Harrison Rate Base costs, requiring that a portion of that recovery be more than fully covered by net margins from the sale of excess capacity and energy in the PJM Markets, so that customers would not be responsible for the Acquisition Adjustment portion of the Harrison Rate Base. Only the WVCAG opposed the Joint Stipulation. Further, the Harrison Order, Commission Case No. 12-1571-E-PC, was appealed to the Supreme Court of Appeals of West Virginia by the WVCAG and was affirmed by the Supreme Court by Order in West Virginia Citizens Action Group v. Public Serv. Comm'n, 758 S.E.2d 254 (W. Va. 2014).

## B. Need for Capacity

One of the major arguments of the opponents of the Transaction is the lack of need for additional capacity for Pleasants. Most parties opposing the Transaction took issue with the use of a winter peak to determine a capacity deficiency and to support a need for capacity. After the advent of PJM capacity rules, the capacity “need” of a load serving entity (LSE) is based on its load during the PJM peak summer months. No matter how much higher the Companies’ peak demand is in the winter months, it is not required by PJM rules to either own or purchase capacity to meet that winter demand. PJM acquires sufficient capacity to serve its summer peak plus a reasonable reserve margin. Because PJM has lower winter peaks, the capacity it has acquired to meet the summer peak is more than enough capacity to serve the winter peaks of all of its members, including the Companies.

Mon Power supports its decision to own capacity in excess of its PJM requirement by arguing that language in the Harrison Order and the statutory IRP language require the Companies “to ensure the ownership of capacity in excess of load, now and in the future, especially taking into account necessary reserve margins of 16.6 percent.” We do not agree with that argument. The statutory IRP language is:

The plan shall compare projected peak demands with current and planned capacity resources in order to develop a portfolio of resources that represents a reasonable balance of cost and risk for the utility and its customers in meeting future demand for the provision of adequate and reliable service to its electric customers as specified by the Public Service Commission.

W.Va. Code §24-2-19(d).

There is nothing in the Harrison Order or the above-quoted language, or any other portion of the IRP statute, that requires an electric utility to own capacity to meet its load requirement. In addition, while “projected peak demands” are required by the statute, the planned capacity resources are left to the discretion of the utility, subject to the requirement that the portfolio of capacity resources provides adequate and reliable service and represents a reasonable balance of costs and risks. The utility may decide, as Mon Power has, to own capacity to meet the peak load or it may decide to meet the load with a “portfolio of resources” that is a combination of owned capacity and purchased power. Purchased power may include purchases from the PJM Market.

It is the responsibility of the Commission to approve or disapprove those utility contracts and agreements that are subject to our jurisdiction and to allow cost recovery of reasonable and prudently-incurred costs. This proceeding is part of that Commission process in which we must determine the prudence of the Companies’ decision, considering the statutory tests specified in W.Va. Code §24-2-12, §24-1-1, and other

applicable Sections of the Code. Our decision is not preordained by a statutory requirement that the Companies meet their winter peak with owned generation capacity; moreover, we do not agree that language in the Harrison Order directed Mon Power to meet future winter peak requirements with generation capacity that it owns.

The facts and circumstances of the Companies' capacity and energy needs at the time of the Harrison acquisition in 2012 were significantly different from the Companies' current needs. When we were considering the Harrison acquisition, the Companies presented evidence that they were unable to meet their summer capacity requirements under PJM rules. They made no attempt to justify the need for capacity on a shortfall in meeting winter load requirements that were also in excess of summer load requirements. Thus, in the Harrison case we were addressing only a capacity shortfall vis-à-vis PJM requirements. In addition, the evidence presented in the Harrison case demonstrated that the Companies could not meet annual energy requirements. With Harrison, the Companies could not only meet annual energy requirements, but would also have significant excess energy generation capability, above internal energy requirements.

The Companies did not attempt to support the current proposed Pleasants Transaction based on a need for energy. In fact, the Companies projected their energy needs around 16 million MWh, growing to 17.5 million MWh by 2020 and to 20 million MWh by 2030. Cos. Ex. BDE-D at BDE-2. In Harrison, the Companies projected that, after approval of the Harrison transaction (which was approved and consummated), energy generation would be around 23.3 million MWh per year. Thus, because of vastly differing facts, circumstances and evidence, the Companies cannot find support in the language of the Harrison Order for the need to own Pleasants.

Aside from their interpretation of W.Va. Code §24-2-19(d) and the language from the Harrison Order, the Companies made other and new arguments for owning capacity to meet internal winter peak load requirements. The Companies did not present a compelling case with supporting evidence for the need to acquire their own capacity, although they strongly supported the benefits of owning Pleasants versus owning any other capacity available through the RFP. The Companies set the stage for need in their Petition when they state:

The need to cover this capacity deficit is the primary motivation for Mon Power's proposal to acquire Pleasants, and this need alone serves as the compelling reason for the Commission to approve it.

Petition at 5.

The need for the capacity and some basic detail of the Pleasants capacity is further mentioned in direct testimony of Ms. Kauffman:

Through the Transaction, Mon Power will acquire an additional 1,300 MW of installed generation capacity (expected 1,159 MW unforced capacity) in

order to provide the energy and capacity needed to meet the Companies' projected requirements through 2022, minimizing or eliminating the need to rely on market purchases during that period.

Cos. Ex. HCK-D at 5.

The Companies attempt to justify their need for capacity to serve peak load in the winter, which is not required by PJM, with certain market rules of PJM that established the capacity resources needed to serve summer load. For example, Mr. Ruberto testified:

Mon Power determined that the [PJM] Capacity Performance market design would have a significant impact on the value of Mon Power's indirect interest in the Bath County Pumped Storage Project (the "Bath County Project") located in Warm Springs, Virginia. Mon Power's interest in the Bath County Project represents 487 MW of capacity. Mon Power concluded that this capacity value would be reduced by approximately 50% beginning in the 2020-2021 PJM Delivery Year due to certain availability requirements imposed on Capacity Performance resources related to system emergencies.

Cos. Ex. JAR-D at 6.

Although the PJM Market Rules and availability requirements are important in evaluating the extent to which capacity should be offered for sale in the PJM Market, those rules do not affect the capacity that is actually available to serve internal load. The Bath County facility has the capacity to serve 487 MW of internal load, regardless of adjustments in its PJM Market capacity bid increment due to concerns over Capacity Performance rules of PJM.

It appears to the Commission that the Companies have mixed and mismatched their desire to meet internal load with owned-capacity at the time of their winter peak with the PJM requirement to have available a PJM-assigned capacity level based on summer peaks. This mismatch results in a significant overstatement of the amount of installed capacity needed to meet reliably the internal winter peak and provide a reasonable reserve margin.

After forecasting a winter peak, the Companies factor the projected peak upward by 16.6 percent to provide for reserve margins. Cos. Ex. BDE-D at BDE-1. For example, Mr. Eberts projected a winter peak demand in 2020/2021 of 3,421 MW. He added a 16.6 percent reserve margin to that number to arrive at a "Peak Demand plus Reserve Margin" of 3,988 MW. Assuming that a 16.6 percent reserve margin is reasonable, and further assuming that owned-capacity should be available to meet internal load plus a reasonable reserve margin, the math employed by Mr. Eberts may determine a reasonable target for installed capacity (ICAP). The Companies, however, do not compare the 3,988 MW projected winter peak plus a 16.6 percent reserve margin

to installed capacity. They instead compare that peak to the UCAP values assigned to their capacity by PJM that are expected to be 2,983 MW, excluding Bath County. The Companies thus assume that their capacity deficiency in the winter of 2020/2021 is going to be 1,005 MW, excluding Bath County. Cos. Ex. JAR-D at 7.

We question this mixed comparison of PJM UCAP values that PJM will use to determine whether the Companies are meeting their summer peak load requirements, to the Companies' winter load projections, plus a 16.6 percent reserve margin. That comparison is not reasonable for purposes of evaluating whether the Companies own and have under contract sufficient capacity to meet their load requirements plus a reasonable reserve margin.

Historically, the Commission has calculated the deficiency by comparing the Companies' peak, adjusted upward for a reasonable reserve margin, to their installed capacity (including contract capacity). The Companies, however, did not present evidence on their installed capacity.

Using the Companies' UCAP approach to measure the sufficiency of capacity to meet their winter peak load requirements might be reasonable with a more realistic reserve margin calculation. Mon Power, however, did not present evidence of a more realistic reserve margin taking the UCAP downgrading of its capacity into consideration, or what methodology PJM applies to arrive at the peak load requirement for an LSE. That is not surprising because PJM would not normally be making a load plus reserve projection for winter months. Without ICAP information in the record, which we could compare to the projected winter peak plus a 16.6 percent reserve margin, and without evidence on a winter peak plus a more realistic reserve margin to compare to UCAP, we are left to calculate a more realistic deficiency by comparing the unadjusted projected winter peak to UCAP.

The Companies have a projected peak demand in the winter of 2020/2021 of 3,421 MW. Comparing that number to the 2,983 UCAP value of owned and contracted capacity, excluding Bath County, results in a deficiency of 438 MW instead of 1,005 MW. The addition of 487 MW of Bath County that was completely omitted from the Companies' projected capacity resources results in a small surplus. When the winter supply/demand balance does become negative, it is not likely to grow near to the level of supply provided by Pleasants. The prudence of acquiring 1,300 MW of capacity to meet a winter supply deficiency that is much smaller than that amount, and which is not required under PJM Rules, is not clear, particularly considering that the Companies have a large surplus of expected energy generation in excess of their internal needs, even before the acquisition of such a large block of additional generating capacity.

Although the Companies may have overstated their case for needing to own additional capacity at any level, let alone at the level of 1,300 MW, they nevertheless made a case that ownership of that much capacity would benefit West Virginia ratepayers in several ways. There would eventually be a summer capacity shortfall of PJM

requirements in the absence of the Pleasants Transaction and that will have to be met by some capacity acquisition. The expected excess energy that will be produced by additional owned capacity that is not needed to serve internal load can, at the right prices, be sold in the PJM energy market at a net margin that will benefit West Virginia customers. The probability of having permanent excess energy over native load requirements to sell at a profit to benefit customers and also having temporary excess capacity over native load requirements to sell at a profit to benefit customers was described by Ms. Kauffman:

[T]he Transaction will provide the opportunity for energy sales (and for capacity sales initially) over and above those needed to provide the Companies' customer requirements. The net revenues from energy sales and/or capacity will be direct offsets to ENEC expenses, and have the potential to materially reduce customer rates.

Cos. Ex. HCK-D at 10.

The Companies have exercised their discretion to choose to own Pleasants. While we find that the need to own Pleasants is not nearly as great or critical as Mon Power has argued, the prudence and risk of the decision lies in a balancing of a number of factors, including the impact on ratepayers. The rate base and fixed operating expenses of owning Pleasants will cost ratepayers approximately \$111 million per year. Cos. Ex. REV-D, at REV-1. These costs are projected by the Companies to be offset initially by net margins from PJM capacity, energy and ancillary service transactions of approximately \$135 million per year. Id. at REV-10. The Companies project even larger net margin benefits to "materially reduce customer rates" in the future. We must consider the likelihood of realizing these benefits to determine if the Transaction is in, or contrary to, the public interest.

### C. The RFP Process, Selection of CRA and Affiliated Transactions

The Intervenors urged throughout the hearing and in their briefs that (i) the affiliated relationship between the Companies and FirstEnergy; (ii) the selection of the submission from FirstEnergy corporate affiliate, AE Supply, as the proposal to be accepted; (iii) the fact that CRA had performed similar undertakings for FirstEnergy or its affiliates in the past; and (iv) a number of other claimed dangers of dealing with an affiliate, make this a transaction that the Commission should not approve. While strongly worded, many, if not most, of the assertions about undue influence or lack of a level playing field were simply bald, conclusory statements or assertions about specters, possibilities or likelihoods of undue influence. At best they were not probative, meaningful or supported by persuasive testimony and at worst were just plain incorrect under the West Virginia statutory and case law.

In fact, the Commission notes that the Companies could have simply negotiated the Transaction directly and were not required to use an RFP. They did so because of past complaints and arguments raised in cases in which the Companies did not use an

RFP. Monongahela Power Company and The Potomac Edison Co., Case No. 12-1571-E-PC (Commission Order October 7, 2013) (Harrison Order); aff'd. West Virginia Citizen Action Group v. Public Serv. Comm'n of W. Va., 233 W. Va. 327, 337, 758 S.E.2d 254, 265 (2014). Furthermore, the mere existence of the need for approval of a W.Va. Code §24-2-12 transaction (and the existence of an affiliated relationship) is not a basis to reject an affiliated transaction or affiliated relationship absent a showing of fraud, abuse or undue influence. Such a requirement distorts the meaning and intent of W.Va. Code §24-2-12 and flies in the face of the holding of the Supreme Court in the Harrison Order.<sup>21</sup>

The Commission must examine any affiliated transaction (as we do any other W.Va. Code §24-2-12 transaction) and is required to apply to that transaction a level of due diligence consistent with the requirements of W.Va. Code §§24-2-12 and 24-1-1. Affiliated transactions are not prohibited, nor is there anything inherently evil or improper about affiliated transactions. A review of an affiliated transaction is a results-oriented analysis that determines whether the requirements of W.Va. Code §24-2-12 are met and not simply whether there is the existence of an affiliated relationship. While there has been much asserted about the affiliated relationships, we see nothing in the record to establish that the negotiated terms of the Transaction between the affiliated parties are fraudulent, abusive, the product of undue influence, or a basis for denying the Transaction.

Staff and CAD argued that using CRA was improper, or at least suspicious, because CRA had millions of dollars in contracts with FirstEnergy. Staff appears to be concerned that CRA could not be an independent evaluator of bids that included bids from another FirstEnergy affiliate. This concern is not supported by any proof that CRA acted unscrupulously or in any way deliberately tilted its evaluation in favor of the Pleasants bid. We do not find any wrongdoing or imprudence in using CRA, which is a large multi-national firm providing many clients with many services. Absent some showing of fraud or abuse, we will not impute bad intentions to CRA just because of its business relationship with FirstEnergy; moreover, the Staff witness confirmed that the

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<sup>21</sup> On the contrary, the West Virginia Supreme Court, in discussing similar arguments made about affiliated transactions stated:

This Court finds that there is evidence to support the Commission's finding that the transaction at issue did not provide an unfair advantage to any of the parties. Significantly, inter-affiliate transactions are not *per se* invalid under W. Va. Code § 24-2-12. Moreover, this Court has found it proper for the Commission to approve inter-affiliate transactions. *See United Fuel Gas Co. v. PSC*, 154 W.Va. 221, 174 S.E.2d 304 (1969) (reversing the PSC's denial of a realignment plan between public utilities all of which were subsidiaries of a parent holding corporation). The Commission specifically found that the transaction at issue does not give one party an undue advantage over another party, and the petitioner has failed to convince us that this finding is in error.

West Virginia Citizen Action Group v. Public Serv. Comm'n of W. Va., 233 W. Va. 327, 337, 758 S.E.2d 254, 265 (2014) (emphasis added).

Pleasants bid was far superior to other bids received in producing the lowest cost to the Companies.

Finally, there is some consternation from opposing parties that the bid structure limited bids to “bricks and mortar” generation that would be owned by Mon Power. By then requiring a facility to be located in the APS Zone of PJM, these opposing parties complain that the bid structure virtually assured that Pleasants would be the winning bidder.

The Commission does not find these arguments to be persuasive reasons for denying the Transaction. We believe that the issue before us is whether the proposed Transaction will be a reliable and economical source of capacity and energy that does not unreasonably burden ratepayers with excessive, or imprudent costs. Further, as we have indicated, the Transaction will be weighed and balanced against the public benefits and the impact on current and future ratepayers and the State. As we address below, the primary test we will use to determine the economic benefits of the Transaction is the relationship of base and ENEC cost of ownership and operation of Pleasants as measured against the PJM Market and the benefits of ENEC credits that can be derived to benefit customers when excess energy and capacity not needed to serve native load is sold in the market at a positive net margin.

#### D. Risk Sharing as a Condition of the Transaction

The word “risk” took on a pervasiveness and ubiquity in this case that was mind numbing. Never has one word or phrase been so overused in briefs and testimony before this Commission. Virtually all of the Intervenors and the Staff suggested at the hearing and in briefing that any and all aspects of the Transaction expose the ratepayers to “too much risk” and hence *a fortiori* any approval of the Transaction was unacceptable without some level of greater “risk sharing” by the Companies.

This “risk analysis” included suggestions by CAD, Staff, WVEUG and others that the Transaction should not be approved because of the one-sided nature of that risk sharing. There were over 450 references to the “risk” of the Transaction peppered in the briefs of the parties to say nothing about the prefiled and hearing testimony. According to the Staff and Intervenors, those risks arose from many (and more accurately based on a review of the briefs) all phases or aspects of the Transaction.

Every aspect of every business, including the sale of public utility services, can be stated as a risk, to wit: risks that economy will go bad, no one will buy the product, no one will make money, suppliers will raise prices for commodities, customers will leave the state, products will be defective, alternative products might come into existence, severe weather may disrupt facilities, etc.

The Commission faces arguments in this case about real, but in many instances, speculative, uncertain, potential or possible risks that run a broad spectrum of magnitude

and likelihood. Those arguments, if adopted wholesale by the Commission, could be the basis to preclude the Commission from approving almost any other transactions in the future. A transaction does not need to be “risk free” before we approve it. There will always be some level of financial, business or regulatory risk inherent in any transaction that we examine under W.Va. Code §24-2-12. Ratepayers face risk in the service they receive from public utilities. We cannot insulate the ratepayers from all risk.

Rates of public utilities are affected by any number of unanticipated needs for capital improvements, escalating O&M expenses, and a host of other items that impact the utility’s cost of service by escalating expenses or depressing revenues. Never in a transaction of relatively recent vintage has there been an attempt to assert that every potential risk was grounds for denying the transaction. It is prudent to consider, contemplate and to safeguard against risk that is reasonably likely to occur. Our concern in this case is the eagerness and united front that “a diverse assemblage of groups that represent widely differing viewpoints” have indicated is too much risk and that the Commission must guard against all of it.

In this case, Pleasants is being offered for sale to the Companies at what would seem to be a favorable price, significantly below the depreciated original cost of the assets. The Commission has reviewed all of the testimony and briefs in this case and concludes that there is potential value and merit to the current and future ratepayers, the utility and the State to approve the Transaction, subject to certain conditions, notwithstanding some of the asserted risks to ratepayers. We can attempt to take reasonable steps to recognize and minimize those risks.

#### E. Possible Conditions for the Transaction

Several parties in this case have proposed mechanisms that would tie the rate allowance for future Pleasants revenue requirements on a market comparison. The Staff proposal is for a ten-year limitation on Pleasants cost recovery such that the amounts paid by customers in any year would not exceed the value of the Pleasants capacity and energy sold into the PJM Market.

As described by Mr. Short, the condition applied to cost recovery would be quantified by comparing the net operating costs incurred “as a result of acquiring Pleasants” to the total revenue received from PJM “associated with power from Pleasants.” If the net operating costs are less than the total PJM revenues, the acquisition of Pleasants would prove to be superior to the market option, and there would be no adjustment to disallow full cost recovery. If, however, the net operating costs in any year are greater than the total PJM revenues, the acquisition of Pleasants would prove to be worse than relying on the market, and an adjustment should be made to limit the rate burden on customers to the cost that is equivalent to the market cost.

To offset the risk to the Companies that they may receive rate recovery that is less than full traditional revenue requirements if the market costs are lower than the costs

associated with ownership of Pleasants, Mr. Short proposed that the Companies receive 25 percent of the excess if market values are higher than the base rate and net ENEC costs associated with Pleasants. This 25 percent would be available for two years after acquisition, and would reduce to 20 percent in the third and fourth years after acquisition, 15 percent in the fifth and sixth year, 10 percent in the seventh and eighth years, and 5 percent in the ninth and tenth year.

WVEUG witness Baron proposed a different risk sharing approach whereby the Companies would be responsible for 25 percent of any excess Pleasants full revenue requirements over the market value of Pleasants capacity and energy, and the Companies could retain 25 percent of the benefit of any excess market value over Pleasants full requirements revenue requirements. WVEUG Ex. SJB-D at 29. Mr. Baron also suggested that the 25 percent share of benefits and detriments could be phased out over a ten-year period. Id. at 31.

The Companies argued that the proposal to subject full cost recovery of Pleasants to conditions such as those proposed by Staff or WVEUG is unreasonable and contravenes the cost recovery model applicable to utility investments and to Mon Power's other generating stations. Cos. Init. Br. at 44. The Companies see no distinguishing factors that would justify differing ratemaking treatment of the costs of Pleasants from those of Harrison and Fort Martin. They point out that except for a condition applicable to the full recovery of the Acquisition Adjustment on Harrison, the market risk attendant to the operations of Harrison and Fort Martin are borne by the customers. The Companies believe that the Parties hope to extract a concession in return for Transaction approval. Id.

The Commission does not accept these arguments by the Companies. We agree with Staff witness Eads regarding a new choice for supply:

In the past, there were effectively only three choices of supply available from which a utility could choose and on which a decision by the Commission was required - build generation, buy generation or enter into a bilateral contract for firm power. Risk avoidance was a significant component of the decision process. Those risks involved such aspects as:

- The potential of acquiring, and having to pay, for more capacity than customers might require.
- The potential for selecting the wrong type of capacity (peaking or base load).
- Selecting a generating source which ultimately requires a more expensive fuel supply.
- Unanticipated environmental requirements and restrictions that alter the original anticipated value of the source.

- Fuel supply disruptions.
- Obsolescence causing premature retirement.
- Price volatility.

Today a fourth choice exists with a much more limited risk profile — the PJM Market. While not risk free, electing to purchase power in the market would avoid many of the risks associated with traditional sources. For the most part, the primary risk of the market would involve the lack of control over what is to be paid and some measure of possible price volatility.

Staff Ex. TRE-D at 35.

The Commission notes that the circumstances regarding need for capacity and energy are also different in this case from the circumstances underlying the decisions to build capacity in the past or to acquire capacity through the Fort Martin and Harrison bi-directional transfer cases. These changed circumstances and the availability of the PJM Market Option for power supply represent a significant distinguishing factor from past decisions to build or contract for capacity and energy.

The Companies also argue that the Staff proposal is unfairly tilted toward customers. They argue that underwriting 100 percent of detriments relative to the market while receiving 25 percent, or less, of any benefits relative to the market is an unfair, asymmetrical, proposal. We considered that argument in developing an alternative cost recovery condition.

The Commission, during the hearing, asked about an alternative concept that would finalize an approval for the Transaction, but require a delay to determine the direction of the market and to test the reasonableness of the Companies projected NPV benefits of Pleasants, vis-à-vis the market option. Tr. V at 64-74.

The Commission discussed with Mr. Schlissel, the witness for WVSUN/CAG, the extent of the Commission's specific legislative authority to enter an order granting approval of the Transaction now, conditioned only on (i) delaying or deferring the consummation of the Transaction until a date certain and (ii) on certification by the Companies and AE Supply that certain objective parameters have been met. *Id.* That proposal would allow time, at least in the near term, to see if the positive scenario portrayed by the Petitioners or the gloom or doom scenario of the Intervenors actually comes to pass, or at least to see the direction in which the trends are heading. If the Transaction, after a period of eighteen to twenty-four months, continues to remain positive, and the Petitioners could certify that the Transaction had been positive for the Companies and other stakeholders for that period of time, based on objective criteria fixed at the time of the Order, the Companies could close on the Transaction. On the other hand, if the Petitioners were unable to so certify, the Transaction could not be closed.

Even though this approach would have approved the Transaction (subject only to conditions of no significant changes in the ability of Mon Power to sell excess capacity and energy in the PJM market, free of any new restrictions or limitations, and that Mon Power's projections of customer benefits remained realistic and possible), apparently no one warmed to that approach. The Companies identified factors that they contended made the arrangement "infeasible and even unwise." Cos. Init. Br. at 49. We tend to believe that the Companies overstated the infeasibility and lack of wisdom in current approval of the Transaction with a conditional delay in closing.

The Companies suggest that AE Supply is not likely to accept a delay when its plan is to rid itself of its competitive generation business. Cos. Init. Br. at 49. They also suggest that there is no provision for delay in the Purchase Agreement, and even if it was willing to delay, AE Supply might not hold its sale offer at \$195 million.

The Companies further criticize a delay on the grounds that it would jeopardize benefits of a planned rate reduction for 2018, and the positive impact of known increases in capacity prices in 2017-18 and 2018-19 will be lost as well. The Companies also expressed concern for AE Supply operating the plant under a cloud of uncertainty occasioned by a delay, and pointed out that this Commission has no jurisdiction to order AE Supply to operate the plant as would be expected in the normal course of an ongoing business. The Companies suggest in the Initial Brief that the hypothesized delay will present many more pitfalls than advantages. Cos. Init. Br. at 51.

We certainly cannot force the Companies to accept that proposal. We do offer the following comments on the problems identified by the Companies.

First, nothing prevented the Companies from requesting clarification of whether the Commission contemplated future "attendant conditions" before this response. The Commission, moreover, never contemplated ordering AE Supply to accept a delay. Accepting a current approval with a conditional delay in closing would always have been a decision that was left to the business judgment of AE Supply.

Second, if the Parties had asked, the Commission could have indicated that our approval with a closing delay would have been conditioned on the \$195 million price. If that was unacceptable to AE Supply, AE Supply would be free to decline or petition for modification.

Third, while it is true that a delayed closing would also delay the rate modifications proposed by the Companies in this proceeding, if the Commission had approved acquisition, but with a delayed closing, foregoing the projected market benefits of Pleasants in 2018 would have been within our prerogative if we believed that was the best way to assure the reasonableness of future benefits projected by the Companies.

Fourth, clarification of the current market policy uncertainties that may eventually be resolved in a manner detrimental to West Virginia ratepayers is precisely what is needed to allow the closing to proceed. Commission approval would have been given, and clarification of current market policy and initiative uncertainties would not have overturned that approval unless the clarification showed the likelihood of detriments that would render going through with the closing as being contrary to the public interest. Any new market policies or initiatives that appeared contrary to the interest of West Virginia ratepayers could occasion further Commission consideration of the transaction, but that would only affirm the prudence of the Commission's conditional closing delay.

Fifth, AE Supply would have been free to operate the plant at its discretion. Acceptance of the delay would be up to AE Supply. If AE Supply accepted the delay, operated the plant in a manner that would jeopardize the capabilities of the plant to continue to run as contemplated by the Companies and the Commission, it would do so at its own peril of jeopardizing the closing.

The suggested approach would have provided a possible path for consummation of the Transaction, absent significant changes demonstrating that projected net customer benefits were not likely achievable. In that event, there might have been further Commission consideration of the transaction, but that consideration would be much more limited in scope than this proceeding. In the event that circumstances were such that the projected net benefits to customers were so unlikely that the Commission must stop the closing of the Transaction, that fact would benefit customers and affirm the prudence of the Commission's conditional closing delay.

## **VII. SUMMARY AND GENERAL DECISION**

Although, as discussed in the Introduction, there are potential external benefits to the economy of the State, the local and regional areas around the Pleasants power plant, plant employees, and present and future ratepayers, these benefits do not outweigh the potential detriments to customers. We appreciate the efforts of the Companies to assure us that the NPV of costs and net market transactions from Pleasants ownership will be a significant positive value which will benefit customers. We have determined, however, that the uncertainties of achieving those net benefits, at the level projected by the Companies, are high. PJM market prices have been low in recent years. It appears that there is a high likelihood of an extended period of low PJM market prices and continuing evolution of PJM Market rules may not be tilting in a direction that will allow benefits to the extent projected by the Companies.

Because the Companies have steadfastly supported the reasonableness of their market analyses and the projections of a significantly positive NPV of Pleasants net cost, they should support their analyses by accepting some responsibility if market prices stay low or Pleasants costs escalate. A commitment by the Companies and FirstEnergy to that effect will remove our concerns, at least to the point of removing concerns that the NPV of Pleasants could prove to be a huge negative number, shouldered solely by ratepayers.

The Commission believes that the facts and circumstances of this case, and considering the alternative market option that is readily available to the Companies, require a departure from the historic capacity acquisition adjudication where the only reasonable options were construction or acquisition of rate based generation resources or long-term fixed requirements contracts for power supply.

Load serving entities now have a reasonably secure market option where capacity and energy are available at competitive prices that many believe have resulted in, and will continue to result in, the benefits of competitive pricing by the most efficient and economical resources. The market may serve as a point of reference against which the prudence of the historical model of self-generation by our electric utilities may be measured and evaluated.

The Commission is concerned that the trend in PJM market prices is not showing the signs of the upturn projected by the Companies that would produce the \$636 million NPV benefit of Pleasants ownership suggested by Mon Power. The average day-ahead energy market prices have dropped into the low \$30 per MWh range in recent years and do not show significant signs of recovery.

PJM Capacity Prices tend to move irregularly, but the trend has definitely turned down. Capacity prices per Megawatt Day are \$126, \$136, \$59, \$120, \$164, \$100, and \$77 in delivery years beginning in 2014 through 2020, respectively.

These actual recent PJM market price data support a requirement that the Companies provide something more than educated speculation of increasing market prices and a \$636 million NPV benefit of Pleasants ownership versus reliance on the market.

The Commission cannot force the Companies and FirstEnergy to back their projections of market prices with guarantees. We do, however, find that the lack of immediate need for capacity to meet PJM summer capacity requirements, the lack of need for energy to meet internal load requirements, the uncertainty of a benefit and amount of benefit from market transactions made possible by Pleasants ownership, and the certainty of the availability of the PJM market to meet any winter internal load or summer capacity obligations if and when such occur, lead us to conclude that the proposed acquisition of Pleasants is contrary to the public interest unless the Companies and FirstEnergy agree to shoulder the responsibility of the excess cost of Pleasants, vis-à-vis the market, if their projections are significantly in error.

The Commission does not expect the Companies and FirstEnergy to underwrite their projections absolutely. In other words, there does not need to be a guarantee of a \$636 million NPV benefit for customers; neither do we expect an agreement that does not allow a fair opportunity for the Companies to recoup cost recovery foregone during periods of low market prices during periods of high market prices. We do find, however,

that a guarantee that the Companies will compensate customers during any year that market prices produce capacity and energy revenues from Pleasants that are below the full revenue requirements imposed on customers due to Pleasants is not only reasonable, but also it is appropriate for a finding that this particular transaction is not contrary to the public interest.

On the flip side, we find that it would be fair and reasonable to allow the Companies to record a deferred debit, regulatory asset, on their books equal to the amounts, if any, of compensation to customers when market revenues are insufficient to cover Pleasants costs and be allowed to recover such deferrals by retaining positive margins received from PJM in a subsequent year or years, up to the level of accumulated deferrals.

For example, if in the first year after acquisition, the base and ENEC Pleasants cost responsibilities paid by customers is \$300 million, and the value of Pleasants capacity and energy sold in the PJM market is \$280 million, the Companies would incur an obligation to return \$20 million to customers, as directed by the Commission. If that \$20 million is returned to customers in the form of rate credits, and the next year the Pleasants cost responsibilities paid by customers is \$300 million, and the value of Pleasants capacity and energy in the PJM market is \$305 million, the \$5 million margin that would normally be credited to the benefit of customers would, instead, be retained by the Companies. That would leave the Companies with \$15 million of potential future market benefits that they could retain. If in the third year, the Pleasants cost responsibilities of customers is \$300 million, and the value of Pleasants capacity and energy in the PJM market is \$340 million, the Companies could retain \$15 million of the benefit and the remaining \$25 million would be credited to customers using the normal ENEC credit mechanism, or, if the ENEC is no longer in effect, any other rate-setting mechanism as directed by the Commission.<sup>22</sup>

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<sup>22</sup> We note that the condition and calculation methodology herein described is not the same as the condition placed on Mon Power for full recovery of the Acquisition Adjustment allowed in the Harrison case. In the Harrison case, we established a requirement that net margins attributable to Harrison market transactions that result in net revenue requirements credits that benefit customers must equal two times the annual revenue requirement on the Harrison Acquisition Adjustment before Mon Power could fully recover those revenue requirements. The intent and purpose of the Harrison guarantee, which required a net benefit to customers, is different from the guarantee that this Transaction is conditioned on, which requires market revenue equal to the total cost of Pleasants or a deferral of excess Pleasants costs above market revenue.

#### A. McElroy's Run Impoundment and Dam<sup>23</sup>

Turning to the McElroy's Run Impoundment and Dam, the Commission determines that there is sufficient concern regarding the issue of liability that there should be protections for the ratepayers from the impact of any future liability regarding the McElroy's Run Impoundment and Dam. The Commission will require that Companies submit appropriate agreements executed between Mon Power and a qualified FirstEnergy corporate entity that will exist in the future, pursuant to which that entity will indemnify, defend at its expense, and save Mon Power and its ratepayers harmless from any liabilities, costs, and claims, including judgments, fines, and penalties, or other costs or expenses, imposed upon Mon Power to the extent related to the Pleasants Plant or its operations prior to the transfer from AE Supply to Mon Power and the McElroy's Run Impoundment and Dam, whenever arising.

Because indemnity agreements can be complex, contentious and complicated and can take on a life of their own, we will not herein spell out the terms that we expect in the indemnity agreement. What we require is that the indemnity should fully protect Mon Power and its ratepayers from any liability associated with the Pleasants Plant or its operations, including the McElroy's Run Impoundment and Dam, prior to the transfer of ownership, and also cover the McElroy's Run Impoundment and Dam subsequent to the transfer.

#### B. Temporary Surcharge and Ratemaking

Regarding recovery of costs, the Commission will allow the Companies to add a Temporary Surcharge to their tariffs. The Temporary Surcharge must be recalculated to reflect the Federal Income Tax rate under the Tax Cuts and Jobs Act of 2017.<sup>24</sup> The revenue requirements and rates established at closing will not be subject to either prospective revision or retrospective true-up during their pendency. All base revenue requirements for Pleasants will be rolled into base rates in the Companies' next base rate case and the Temporary Surcharge will cease at that time. It is reasonable, in consideration of testimony by WVEUG witness Mr. Baron asserting that industrial class base rates established in the last base rate case exceeded their cost of service, and referencing testimony by Companies' witness Wise in the most recent base rate case, Case No. 14-0702-E-42T (Commission Order, February 3, 2015, at 11) acknowledging that possibility, to require the Companies to defer Temporary Surcharge amounts billed to their industrial rate schedules. WVEUG Ex. SJB-D at 33. The deferred balance may

<sup>23</sup> The McElroy's Run Impoundment consists of a constructed impoundment area of approximately 253 acres behind a dam. Staff Ex. DWD-D at 5. Testimony referenced the McElroy's Run Impoundment. When the Commission refers to McElroy's Run Impoundment and Dam in the discussion, findings, conclusions and ordering paragraphs, we are referring to the dam, impoundment area and any related structures and improvements.

<sup>24</sup> This recalculation requirement applies only to the Temporary Surcharge Calculation and will not affect future Commission determinations in the currently pending Commission General Order No. 236.1 proceeding.

accumulate carrying costs at a simple interest rate of four percent per year and will be fully recoverable from industrial customers over such period as is directed by the Commission in the first base rate case of the Companies following this Order. The deferral will allow industrial customers an opportunity to present their case regarding base industrial revenue requirements on a prospective basis. The Commission will not reallocate or assign the deferred industrial temporary surcharges to other classes of customers in the next base rate case, regardless of the prospective industrial revenue requirements the Commission determines to be just and reasonable in the next base rate case.

### C. Continued Operations

As discussed above, the Commission considers factors other than impact on ratepayers to determine the interests of customers, the economy of the state, and local economies as part of the decision making process. We have determined that the immediate local, regional and statewide externalities to the Transaction are positive and significant. While these benefits, taken alone, are not sufficient to tip the balance from detriments to ratepayers to benefits from approving the Transaction, the external benefits are genuine, germane and real factors that the Commission considered, and which added weight to our decision to conditionally approve the Transaction. These external benefits, however, disappear if the Companies do not operate Pleasants for an extensive period of time.

The Companies have spoken glowingly of their maintenance programs and ability to extend the life of a generating facility far beyond its original engineering service life. The Companies have stated that Pleasants is a valuable asset with many years of service life ahead. They have argued that they need an asset that can meet capacity and energy needs years into the future, and Pleasants will deliver on that need. Pleasants, they argue, is a well-maintained, modernized facility capable of continuing operations for many years to come. Cos. Init. Br. at 37.

The Commission is relying on the continuing operations of Pleasants for many years to produce the benefits to the state and local economies that were factors in our decision to conditionally approve the Transaction. But beyond that, we also expect reasonable assurances of continued operations well into the future to protect customers against costs associated with premature retirement.

The Companies are in control of the initial decision for premature retirement and can make that an easy decision if they do not operate and maintain the plant as they have described in the record in this case. Their present practices which extend the service life of Pleasants, rather than shorten it include: maintenance practices based upon industry best practices, including a Major Component Integrity Assurance program (defines inspection requirements and intervals on plant equipment), Component Health Reports (summarizes failure history, inspection results and recommended future actions to enable proper outage planning), Advanced Pattern Recognition (real-time modeling system that

analyzes plant operating inputs and anticipates necessary inspection or maintenance activities to prevent failure), Original Equipment Manufacturer advisories to ensure proper maintenance of facilities, robust plant operator training program with an on-site simulator, daily work management practices, and outage work management practices. Cos. Ex. DE-R at 2, 5-7.

In addition, the Companies witness, Evans, touted preventive maintenance at the plant, testifying:

We develop maintenance basis templates for the equipment and systems in that plant and we have preventative maintenance programs in place according to those templates . . . .

Tr. II at 371 (Evans).

The Companies also indicated how new equipment is constantly supplied to assure continuing operations. They stated:

Pleasants has ensured its viability through strategic capital investments over its lifetime. Plant personnel continually assess major components and perform life-extensions and capital placements when and where necessary. Examples include replacements of boiler components, feedwater heaters, and main turbine rotor trains; upgrades of generator rotor components and distributed control systems; and infrastructure investments such as a new stack. Pleasants has also invested capital to ensure that it remains up-to-date from an environmental compliance perspective.

Cos. Init. Br. at 38.

To provide protection to ratepayers, reasonable assurance of continuing external benefits for at least a reasonable period of time, and incentive for Mon Power to operate and maintain Pleasants consistent with the Companies' testimony and statements as summarized above, the Commission will require the Companies to agree to a condition that recovery of undepreciated Pleasants capital costs and reasonable closing costs from customers will be subject to sliding scale limitation, and closure and post-closure costs of the McElroy's Run Impoundment and Dam that exceed such costs already provided for in depreciation rates will not be passed on to West Virginia retail ratepayers at all.

Specifically, if the plant closes within the first eight years after transfer of ownership, no portion of undepreciated Pleasants capital costs or closing costs will be subject to recovery from customers. The percentage of reasonable closing costs and undepreciated capital costs, excluding any closure and post-closure costs related to the McElroy's Run Impoundment and Dam, that will be subject to recovery from customers will increase by twenty percentage points at the beginning of the ninth year after transfer of ownership, and each two years thereafter. Thus, as of the beginning of the seventeenth

year after transfer of ownership, one-hundred percent of undepreciated capital costs and reasonable closing costs, excluding any closure and post-closure costs related to the McElroy's Run Impoundment and Dam, shall be subject to recovery from customers.

Except for the limit on recovery of closure and post-closure costs related to the McElroy's Run Impoundment and Dam, the limitation on the percentage subject to recovery from customers will not apply if the Companies make a filing for full recovery and the Commission determines that the closing is required because of new environmental, regulatory or any other laws or government regulations that require a closing of the plant.

The amount and timing of recovery of undepreciated capital costs and reasonable closing costs shall be subject to a future order of the Commission based on a finding that the costs to be recovered are reasonable and prudently incurred.

### **VIII. CAD MOTION TO DISMISS**

On January 12, 2018, the Federal Energy Regulatory Commission issued its Order Rejecting Disposition and Acquisition of Generation Facilities and Dismissing Assumption of Liabilities (FERC Order). 162 FERC ¶ 61,015 (2018). In the FERC Order, FERC denied without prejudice authorization for the Transaction because the Applicants had not demonstrated that the Transaction is consistent with the public interest. On January 18, 2018, CAD filed a Motion to Dismiss in this Commission's case asserting that, because the FERC had denied authorization for the Transaction, this Commission's case is moot and should be dismissed. On January 22, 2018, Staff filed a Support of and Addition to the CAD Motion to Dismiss. On January 24, 2018, WVEUG filed a letter in support of the CAD and Staff positions.

On January 23, 2018, the Companies filed a letter in opposition to the Motion to Dismiss, noting that the FERC proceeding is not closed. The Companies requested that the Commission leave this docket open until the Companies have reached affirmative decisions on how to proceed and appropriate further action is taken by FERC.

We understand that the time for filing a Motion for Reconsideration with FERC has not yet expired and we acknowledge the Companies' request to leave this docket open. The Commission had the benefit of the FERC Order prior to finalizing this Order. Given that, we believe that it is appropriate for this Commission to complete its work on the Petition in this case and issue this Order so that FERC can have this Commission's thoughts on this matter. We, therefore, deny the CAD Motion to Dismiss and the related filings by Staff and WVEUG in support of the CAD Motion. When the Commission issues a decision on the merits, we typically close our docket as a procedural matter. By issuing a final order in this case, we are not depriving any party of any right provided by statute or rule. The parties have all options provided by Rule 19 of the Commission Rules of Practice and Procedure, 150 CSR 1, and the West Virginia Code.

## **IX. FINDINGS OF FACT**

1. PJM is a summer peaking entity. Cos. Ex. BDE-R at 2-9; Longview Ex. SG-D at 20; Sierra Club Ex. TC-D at 7; WVSUN/CAG Ex. DAS-D at 12.

2. After the advent of PJM capacity rules, the capacity requirements of an LSE are based on its load during the PJM peak summer months and PJM rules do not require Mon Power to own or purchase capacity to meet its winter peak demand. WVSUN/CAG Ex. DAS-D at 12-13.

3. PJM has capacity to serve the winter peaks of all of its members, including the Companies. Staff Init. Br. at 7.

4. PJM is required to assure sufficient capacity to serve its summer peak plus a reasonable reserve margin.

5. The Bath County facility has the capacity to serve 487 MW of internal load. Cos. Ex. JAR-D at 6.

6. The Companies' projected peak demand of 3,421 MW in the winter of 2020/2021 as compared with the 2,983 UCAP value of owned and contracted capacity (excluding Bath County) indicates a deficiency of only 438 MW instead of 1005 MW. Including Bath County leaves a modest surplus of 49 MW. Cos. Ex. JAR-D at 7.

7. In the past, there effectively were only three choices of supply available that a utility could choose – build generation, buy generation, or enter into a bilateral contract for firm power. The PJM Market is a choice for supply with a more limited risk profile than previous choices. Staff Ex. TRE-D at 35.

8. Purchased power, while not risk-free in the market, avoids some of the risks associated with traditional sources. The primary risk of the market is lack of control over price and price volatility. Staff Ex. TRE-D at 35.

9. The Companies' 2015 IRP concluded that existing generation facilities would likely be the lowest cost option for additional capacity. Monongahela Power Co. and The Potomac Edison Co., Case No. 15-2002-E-P (IRP filed on 12/30/15 at 57).

10. The purchase price for the Pleasants Plant is \$195 million, or \$150/kW. Petition at 7; Cos. Init. Br. at 35.

11. PJM market prices have been relatively low in recent years. Sierra Club Ex. TC-D at 14, citing FirstEnergy 2017 10K at 4 (<http://investors.firstenergycorp.com/Docs#gsc.tab=0>).

12. PJM market prices are not trending upward and, under current trends, will not produce the \$636 million NPV benefit of Pleasants ownership suggested in the Petition. Sierra Club Ex. TC-D; WVSUN/CAG Ex. DAS-D.

13. The energy needs of the Companies presented in this case are different from the capacity and energy needs of the Companies at the time of the Harrison acquisition. Monongahela Power Co. & The Potomac Edison Co., Case No. 12-1571-E-PC; aff'd W. Va. Citizens Action Group v. Public Serv. Comm'n of W. Va. 233 W. Va. 327, 758 S.E.2d 254 (2014).

14. Unlike the record in this case, the record in the Harrison case established a need for Harrison capacity to meet summer peaks as required by PJM and the energy shortfalls that were facing the Companies if they did not acquire Harrison. Id.

15. Unlike the record in this case, in the Harrison case the record reflected that the Companies were facing a significant shortfall in meeting their energy requirements with internal generation resources. Id.

16. The Companies do not have an immediate need for capacity to meet PJM summer capacity requirements or internal load requirements. WVEUG Ex. SJB-D at 9, Fig. 1; Longview Ex. SG-D at 19-23; Sierra Club Ex. TC-D at 7-12; WVSUN/CAG Ex. DAS-D at 7-17.

17. Excess energy produced by additional owned capacity not required to serve internal load can, at the right prices and circumstances, be sold into the PJM energy market at a net margin to benefit West Virginia customers. Cos. Ex. HCK-D at 10.

18. The costs of the Transaction can be offset initially by projected net margins from PJM capacity, energy, and ancillary service transactions of approximately \$135 million per year with the possibility of even larger net margin benefits that could reduce customer rates in the future.

19. The preventive maintenance program used by the Pleasants Plant is modeled from the Electric Power Research Institute. Pleasants inspects critical equipment, such as transformers, to ensure reliability and prepare for high-impact, low-probability events. Tr. II at 370-71 and 368, respectively.

20. Pleasants conducts scheduled outages on each unit every three years and performs replacements as necessary. Tr. II at 348.

21. Various externalities related to an array of non-ratemaking implications about employment and jobs, enhancing and preserving the attractiveness of the State as a place for industry to do business, maintaining productive capacity, tax base, and support to local and regional charities and providing governmental financial support and a host of other outcomes, other than rate impact, tend to support the Transaction.

22. The beneficial impact of those externalities lasts only as long as the Companies operate Pleasants.

23. The Pleasants Plant is in reasonably good condition and the present practices and preventive maintenance at Pleasants will extend its potential life.

## **X. CONCLUSIONS OF LAW**

1. The Companies could have negotiated the Transaction directly and were not required to use an RFP by West Virginia Code or case law.

2. The existence of the need for approval of a W.Va. Code §24-2-12 transaction and the existence of an affiliated relationship are not a basis to reject an affiliated transaction or affiliated relationship, absent a showing of fraud, abuse or undue influence.

3. The Commission must examine virtually all affiliated transactions and is required to apply to those transactions a level of due diligence consistent with the requirements of W.Va. Code §§24-2-12 and 24-1-1.

4. Affiliated transactions are not prohibited, nor is there anything inherently improper about affiliated transactions. A review of an affiliated transaction is a results-oriented analysis that determines whether a proposed affiliated transaction satisfies the requirements of W.Va. Code §24-2-12 and not simply whether there is the existence of an affiliated relationship.

5. There is nothing in the record to establish that the negotiated terms of the Transaction between the affiliated parties are fraudulent, abusive, the product of undue influence, or a basis for denying the Transaction.

6. The record does not reflect that CRA acted unscrupulously or deliberately skewed its evaluation in favor of the Pleasants bid.

7. The record in the case does not establish an immediate need for capacity from the Pleasants Plant to meet summer peaks as required by PJM.

8. The record in this case does not reflect that the Companies have a shortfall in meeting their energy requirements with internal generation resources.

9. Neither the Harrison Order nor the IRP Act requires an electric utility to own capacity to meet its load requirement and the utility can arrange to meet its load from a number of reasonable options, including purchases from the PJM Market.

10. While projections of peak demands are required by W.Va. Code §24-2-19(d), the planned capacity resources are left to the discretion of the utility, subject to the requirement that the portfolio of capacity resources provides adequate and reliable service and represents a reasonable balance of costs and risks. The utility may decide to own capacity to meet the peak load, or it may decide to meet the load with a combination of owned capacity and purchased power. Purchased power may include purchases from the PJM Market.

11. The Companies' comparison of projected winter peaks plus a 16.6 percent reserve margin to the PJM UCAP values, which PJM uses to determine capacity resources needed to satisfy a PJM-assigned capacity level based on summer peaks, is a mismatch and results in a significant overstatement of the amount of installed capacity needed to reliably meet internal winter peak and provide a reasonable reserve margin.

12. The Companies' comparison of PJM UCAP values to the Companies' winter load projections, plus a 16.6 percent reserve margin, is not a reasonable basis to evaluate whether the Companies have sufficient owned and contracted capacity resources to meet their load requirements plus a reasonable reserve margin.

13. Without ICAP information in the record, which we could compare to the projected winter peak plus a 16.6 percent reserve margin, and without evidence on a winter peak plus a more realistic reserve margin to compare to UCAP, it is reasonable to calculate a more realistic deficiency by comparing the unadjusted projected winter peak to UCAP.

14. The prudence of the Transaction to acquire 1,300 MW of capacity to meet a winter supply deficiency that is much smaller than 1,300 MW, and that is not required under PJM Rules, is questionable, particularly considering that the Companies have a large surplus of expected energy generation in excess of their internal needs, even before the Transaction.

15. The current likelihood of a period of low PJM market prices and the continuing evolution of PJM Market rules may not support the benefits of the Transaction to the extent projected by the Companies.

16. Considering the alternative PJM market option readily available to the Companies, the facts and circumstances of this case require a departure from the historic capacity acquisition adjudication in which the only reasonable options were construction or acquisition of rate-based generation resources or long-term fixed requirements contracts for power supply.

17. The current and projected cost of acquiring power from the market may serve as a point of reference against which the prudence of continuing the historical practice of self-generation by our electric utilities may be measured and evaluated.

18. The Commission may consider the likelihood of realizing revenue from PJM capacity, energy, and ancillary service transactions to determine if the Pleasants Transaction is in the public interest.

19. An agreement from the Companies and FirstEnergy to recover from customers no more than the value of Pleasants capacity, energy and ancillary services sold in the PJM Market is necessary to protect customers from unjust, unreasonable, and excessive rates and to allow this Commission to determine that the Transaction is in the public interest.

20. Under the circumstances of this case, including the limitation on cost recovery to the value of Pleasants capacity, energy and ancillary service sales in the PJM Market, the Companies should be allowed to record a deferred debit, regulatory asset on their books equal to the amounts, if any, of compensation to customers when market revenues are insufficient to cover Pleasants costs and then be allowed to recover such deferrals by retaining positive margins received from PJM in a subsequent year or years up to the level of accumulated deferrals.

21. The Longview request to withdraw its intervention will be granted, and inasmuch as Longview fully participated in the case and the intervention was not withdrawn until after the close of the record, the testimony and evidence presented by Longview will remain a part of the record in this case.

22. The Commission has jurisdiction over this case pursuant to W.Va. Code §24-2-12 which requires prior Commission approval to enter into a contract with an affiliated corporation, person, or interest "upon proper showing that the terms and conditions thereof are reasonable and that neither party thereto is given an undue advantage over the other, and do not adversely affect the public in this State."

23. There are immediate local, regional and statewide externalities to the Transaction that are positive and significant and lend support to the decision to approve the Transaction as conditioned in this Order.

24. The prudence and risk of the decision on whether to approve the Pleasants Transaction lies in a balancing of a number of factors including the impact of the Transaction on ratepayers.

25. It is prudent to consider, contemplate and attempt to safeguard against risk that is reasonably likely to occur.

26. The primary test to determine the economic benefits of the Pleasants Transaction is the relationship of base and ENEC cost of owning and operating the plant as measured against the PJM Market and the benefits of reduced rates that can be derived for customers when excess energy and capacity, not needed to serve native load, and ancillary services, are sold in the market at a positive net margin.

27. The proposed Transaction, with the implementation of the conditions imposed by the Commission, should be a reliable and economical source of capacity and energy that will not burden ratepayers with excessive, unreasonable or imprudent costs.

28. Because (i) the Companies do not have an immediate need for capacity to meet PJM summer capacity requirements; (ii) the Companies do not have a need for energy to meet internal load requirements; (iii) the uncertainty of a benefit and amount of benefit from market transactions made possible by Pleasants ownership; and (iv) the certainty of the availability of the PJM market to meet winter internal load or summer capacity obligations if and when such need would occur for the Companies, the proposed acquisition of Pleasants is contrary to the public interest, unless the Companies and FirstEnergy agree to shoulder the responsibility of the excess cost of Pleasants, vis-à-vis the market, if their projections are significantly in error.

29. Because there is sufficient concern regarding the issue of liability for the McElroy's Run Impoundment and Dam, there should be protections put in place for the Companies and the ratepayers against the impact of any liability from the McElroy's Run Impoundment and Dam.

30. The Companies should enter into an indemnity agreement with a qualified FirstEnergy corporate entity to protect Mon Power and its ratepayers from any liability associated with the Pleasants Plant or its operations prior to the transfer of ownership, and covering any liability for the McElroy's Run Impoundment and Dam, as further described in this Order.

31. To assure continued external benefits for at least a reasonable period of time, protect ratepayers, and as an incentive for the Companies to operate and maintain Pleasants consistent with their testimony and arguments, the Companies should agree to a condition that recovery of undepreciated Pleasants capital costs and reasonable closing costs from customers will be subject to a sliding scale limitation as described in the Order.

32. Under the circumstances of this case, including the contemporaneous ENEC net credits, the Companies should add a Temporary Surcharge to their tariffs.

33. The Companies should recalculate the Temporary Surcharge to reflect the Federal Income Tax rate under the Tax Cuts and Jobs Act of 2017.

34. The Temporary Surcharge should be continued without prospective revision or retrospective true-up until base rates are established in the Companies next base rate case.

35. The Companies should defer Temporary Surcharge amounts billed to their industrial rate schedules, provided that the deferred balance include a carrying charge at a

simple interest rate of four percent per year and will be fully recoverable from industrial customers over such period as is directed by the Commission in the first base rate case following this Order. Deferred industrial Temporary Surcharges will not be reallocated or assigned to other classes of customers in the next base rate case, regardless of the prospective industrial revenue requirements determined to be just and reasonable in that case.

## **X. ORDER**

IT IS THEREFORE ORDERED that the Petition of Monongahela Power Company and The Potomac Edison Company is denied as filed.

IT IS FURTHER ORDERED, however, that the Commission approves a transfer of the Pleasants Plant from AE Supply to Monongahela Power Company if the parties to the transfer agree to the conditions set forth below and further described in Section VII of this Order:

- a) The Companies will compensate customers through prospective rate credits as determined by the Commission for any year that market sales from Pleasants produce revenues that are below the full revenue requirements imposed on customers due to Pleasants. The first determination of the outcome of this condition will cover the first full twelve-month period following the consummation of the Transaction, or such longer period as the Commission determines will accommodate a review and decision synchronized with the Companies' annual ENEC proceedings. Thereafter, proceedings addressing this condition will be conducted in separate annual proceedings on the same timeline as the annual ENEC cases.
- b) The Companies will defer Temporary Surcharge amounts billed to their industrial rate schedules. The deferred balance may accumulate carrying costs at a simple interest rate of four percent per year and will be fully recoverable from industrial customers over such period as is directed by the Commission in the first base rate case following this Order.
- c) Mon Power and a qualified FirstEnergy corporate entity that will exist in the future will submit for review and approval agreements pursuant to which the entity will indemnify, defend at its expense, and save Mon Power and its ratepayers harmless from any liabilities, costs, and claims, including judgments, fines, and penalties, or other costs or expenses, imposed upon Mon Power to the extent related to the Pleasants Plant or its operations prior to the transfer from AE Supply to Mon Power and the McElroy's Run Impoundment and Dam, whenever arising.

d) Recovery of undepreciated Pleasants capital costs and reasonable closing costs from customers will be subject to sliding scale limitations, as further described in this Order at Section VII, and closure and post-closure costs of the McElroy's Run Impoundment and Dam that exceed such costs already provided for in depreciation rates will not be passed on to West Virginia retail ratepayers, at all.

IT IS FURTHER ORDERED that, except for the limit on recovery of closure and post-closure costs related to the McElroy's Run Impoundment and Dam, the limitation on the percentage subject to recovery from customers shall not apply if the Companies make a filing for full recovery and the Commission determines that the closing is required because of new environmental, regulatory or any other laws or government regulations that require a closing of the plant.

IT IS FURTHER ORDERED that the amount and timing of recovery of undepreciated capital costs and reasonable closing costs of Pleasants, to the extent allowed under the conditions outlined above, shall be subject to a future order of the Commission based on a finding that the costs to be recovered are reasonable and prudently incurred.

IT IS FURTHER ORDERED that a Temporary Surcharge is authorized upon closing, conditioned on a recalculation of the Temporary Surcharge rates to reflect the Federal Income Tax rate under the Tax Cuts and Jobs Act of 2017 and a contemporaneous reduction in ENEC rates as proposed by the Companies and as further described in this Order. The Pleasants base revenue requirements and rates established at closing will not be subject to either prospective revision or retrospective true-up during their pendency. All base revenue requirements for Pleasants will be rolled into base rates in the Companies next base rate case and the Temporary Surcharge shall cease at that time.

IT IS FURTHER ORDERED that the Companies shall defer Temporary Surcharge amounts billed to their industrial rate schedules. The deferred balance may accumulate carrying costs at a simple interest rate of four percent per year and will be fully recoverable from industrial customers, without reallocation or reassignment to other customers, over such period as is directed by the Commission in the first base rate case following this Order.

IT IS FURTHER ORDERED that Monongahela Power Company and The Potomac Edison Company shall, within thirty days of issuance of this Order, file recalculated revenue requirements and proposed tariff sheets in accordance with this Order.

IT IS FURTHER ORDERED that Monongahela Power and a FirstEnergy Corporation entity that will exist in the future shall file within thirty days of this Order the indemnity agreements required by this Order.

IT IS FURTHER ORDERED that, on or after the date the Transaction is consummated, Monongahela Power Company and The Potomac Edison Company shall file an original and six copies of appropriately notated revised tariff sheets setting forth the approved surcharge, to be effective on the closing date of the Transaction.

IT IS FURTHER ORDERED that the Companies make a closed entry filing notifying the Commission of the date of closing.

IT IS FURTHER ORDERED that the Longview Power, LLC Motion to Withdraw as an Intervenor in this case is granted. The testimony and evidence presented by Longview shall remain a part of the record in this case.

IT IS FURTHER ORDERED that the Motion to Dismiss filed by the Consumer Advocate Division and the supporting motions filed by Commission Staff and WVEUG are denied.

IT IS FURTHER ORDERED that the Executive Secretary maintain the information filed under seal in this proceeding separate and apart from the remnant of the case file pending a further Commission Order issued after review of any request to inspect or copy the sealed information.

IT IS FURTHER ORDERED that this proceeding be removed from the Commission docket of active cases on entry of this Order.

IT IS FURTHER ORDERED that the Executive Secretary of the Commission serve a copy of this Order by electronic service on all parties of record who have filed an e-service agreement, and by United States First Class Mail on all parties of record who have not filed an e-service agreement, and on Commission Staff by hand delivery.

A True Copy, Teste,



Ingrid Ferrell  
Executive Secretary

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MONONGAHELA POWER COMPANY and  
THE POTOMAC EDISON COMPANY  
Case No. 17-0296-E-PC

**PROCEDURAL HISTORY OF THE CASE**

**Public Notice**

On April 14, 2017, the Commission ordered the Companies to provide notice of the proposed transfer and the evidentiary hearing. The notice was provided in the statewide publication The Charleston Gazette Mail on April 24 and May 1, 2017, and in ten newspapers in the Companies' service territory, The Journal (April 24 and May 1, 2017), The Exponent-Telegram (April 24 and May 1, 2017), The Inter-Mountain (April 24 and May 1, 2017), The Dominion Post (April 24 and May 1, 2017), The Parkersburg News and Sentinel (June 9 and 16, 2017), The Times West Virginian (June 9 and 16, 2017), The Weirton Daily Times (April 24 and May 3, 2017), The West Virginia Daily News (April 24 and May 1, 2017), The News Tribune (April 27 and May 2, 2017). Affidavits of Publication, May 18, 2017. The Revised Notice of Hearing was published once in The Charleston Gazette Mail. Affidavit of Publication, May 11, 2017.

**Interventions**

The following parties were granted intervenor status in this case: CAD, WVSUN/CAG, WVEUG, Longview, Sierra Club, HCP and BCP, WVCA, and WVBIC. Commission Orders entered April 14, 2017, May 11, 2017, June 1, 2017, and August 30, 2017.

On December 11, 2017, well after entering pre-filed testimony and presenting testimony during the evidentiary hearing, Longview filed a request to withdraw its intervention in the case. Longview stated its support for the Companies' Petition.

**Motions for Protective Treatment**

The Commission deferred ruling on Motions for Protective Treatment filed by the Companies on April 10, 2017, and August 2, 2017. Commission Orders, April 14 and August 21, 2017. The Companies sought protective treatment for direct testimony and exhibits filed by the Companies and (i) Competitive Operational Information, (ii) Competitive RFP and Bid Analysis Information, (iii) Natural Gas, Capacity, and Electricity Price Forecast Information, and (iv) Business Expansion Information. No other parties objected to either Motion.

On September 20, 2017, WVEUG filed a Motion seeking protective treatment for the information submitted in response to Question 21 of the Companies' first discovery

requests. The information was compiled by Michael Messer in his position with WVEUG member Linde LLC. Mr. Messer testified on the effect that the proposed sale may have on Linde. The information for which WVEUG seeks protective treatment pertains to operating costs and the prices paid to Mon Power for electric service. No other party has objected to the request for protective treatment. The Commission ruled from the bench that it would defer ruling on the Motion for Protective Treatment until such time as an objection was raised or a WV FOIA request for the information was filed. Tr. I at 19.

Public Comment

The Companies published Notice of Public Comment Hearings in The Journal (Berkeley County), The Exponent-Telegram (Harrison County), The Inter-Mountain (Randolph County), The Dominion Post (Monongalia County), The Parkersburg News and Sentinel (Wood County), The Times West Virginian (Marion County), The Weirton Daily Times (Hancock County), The West Virginia Daily News (Greenbrier County), The News Tribune (Mineral County), and The Charleston Gazette Mail (Kanawha County, with statewide distribution) on June 9 and 16, 2017. Commission Order, June 1, 2017; Affidavits of Publication, July 3, 2017.

Public comment hearings were held in the service territory of the Companies: (i) the Parkersburg Municipal Building Council Chambers on 3<sup>rd</sup> and Avery Streets in Parkersburg, West Virginia, on September 6, 2017, at 6:00 p.m.; (ii) the Martinsburg City Building, Municipal Courtroom, 232 North Queen Street, on September 11, 2017, at 7:00 p.m.; and (iii) the Monongalia County Judicial Center, Judge Tucker's Courtroom, 75 High Street, Morgantown on September 12, 2017, at 6:00 p.m. The public comment hearings were well-attended and approximately 35 people spoke at each hearing.

Pre-filed Testimony

On March 7, 2017, the Companies pre-filed the Direct Testimony of its witnesses:

1. Bradley D. Eberts – Manager of Load Forecasting, FirstEnergy Service Company; providing a fifteen-year forecast (2017-2031) of the Companies' load peak demand and energy requirements and the methodologies used to develop them. The forecasts included both winter and summer peaks.
2. John Deskins – Director of the Bureau of Business and Economic Research and Associate Professor of Economics at West Virginia University College of Business and Economics; testifying on (i) the historical and fifteen-year forecast (2016-2031) for the Companies' West Virginia service territory to be used for modeling their load and energy forecast and (ii) the economic impact to the local, regional, and state economies of the Pleasants facility.

3. Holly C. Kaufmann – President, West Virginia Operations, Monongahela Power Company; providing an overview of the Petition, the needs of the Companies and the customers, and the Companies' process of seeking additional generation resources and demand response.
4. Robert J. Lee – Vice President in the Auctions and Competitive Bidding Practice at Charles River Associates; describing his role and CRA's role in the Request for Proposals process, how the RFP was created, and how the RFP was fair and competitive.
5. Kurt P. Leutheuser – Project Manager for Black & Veatch; providing a general overview of the technical evaluation of the Pleasants proposal and a physical site visit made on February 20, 2017.
6. Jay A. Ruberto – Director, Regulated Generation and Dispatch for FirstEnergy Service Company; describing Mon Power and the process by which it determined it would need to acquire additional resources to meet future capacity needs and Mon Power's efforts to satisfy its projected need.
7. Thomas Sweet – Director, Global Reference Case, Enterprise Software for ABB Inc.; providing a general overview of the 2016 energy and capacity forecasts provided by CRA and addressing the methodology and specific components of those forecasts.
8. Raymond E. Valdes – Director, Rates and Regulatory Affairs, FirstEnergy Service Company; testifying on the development of the proposed temporary surcharge, calculation of recommended reductions in ENEC rates, and the net effect of these proposed rate changes.

On August 25, 2017, Staff pre-filed the Direct Testimony of its witnesses:

1. Eric F. deGruyter – Technical Analyst, Engineering Division, Public Service Commission of West Virginia; testifying on the Request for Proposals and the load forecast driven by the natural gas activities and growth in Mon Power's West Virginia service territory.
2. David Dove – Engineer Senior/Manager, Engineering Division, Public Service Commission of West Virginia; testifying on the McElroy's Run Impoundment and Pleasants Landfill connected to the Pleasants facility.
3. Terry R. Eads – Director, Utilities Division, Public Service Commission of West Virginia; testifying on the Utilities Division's overall position regarding the requested transfer of Pleasants, including a review of the economic models, adjustments to the CRA economic models, presentation of alternative capacity,

energy and fuel forecasts, forecast supported by the Utilities Division, and discussing and analyzing alternative arrangements to meet Mon Power's growing customer capacity and energy requirements.

4. Edwin L. Oxley – Utilities Analyst, Utilities Division, Public Service Commission of West Virginia; testifying on the rate proposals made by the Companies effective on completion of the Transaction to purchase Pleasants.
5. Randall R. Short – Deputy Director, Carrier and Consumer Operations, Utilities Division, Public Service Commission of West Virginia; collectively presenting the overall Staff recommendation based on the testimony of the various Staff witnesses in this case.
6. Donald E. Walker – Technical Analyst, Engineering Division, Public Service Commission of West Virginia; evaluating the physical plant for any deficiencies in performance, maintenance, and operations of the two 650 MW generating units.

On August 25, 2017, Longview pre-filed the Direct Testimony of its witnesses:

1. Thomas Burnett – Technical Director – Power Generation, Engineering Group, Intertek AIM; identifying concerns regarding the representation of the condition and information concerning Pleasants, including a discussion of fossil power plant components and design, effects of operating practices and plant condition determining plant reliability and useful life, and the operating regime of Pleasants.
2. Steven Gabel – President, Gabel Associates, Inc.; providing an overview of the petition filed by the Companies, including the reasonableness of the customer impact analysis filed by the Companies, whether the installed capacity size of the proposed Transaction is a reasonable commitment to make on behalf of ratepayers, and whether the Companies' process for entering into the proposed Transaction is reasonable and designed to bring about the best results for ratepayers and West Virginia.
3. Nikhil Kumar – Managing Director, Intertek AIM; testifying on the current condition of Pleasants regarding industry trends, benchmark historical operations against peer units, historical and projected plant operating costs, and assessing the reasonableness of the assumptions used in the NPV analysis performed by CRA.

On August 25, 2017, HCP and BCP pre-filed the Direct Testimony of its witness:

Andrew W. Dorn, IV – President, Energy Solutions Consortium, LLC; testifying on the natural gas power plant development projects of ESC Harrison County Power, LLC, and ESC Brooke County Power, LLC, and explaining how these alternatives are better than Pleasants.

On August 25, 2017, CAD pre-filed the Direct Testimony of its witness:

Emily S. Medine – employed by Energy Ventures Analysis, Inc.; testifying on all aspects of the proposed transfer of Pleasants.

On August 25, 2017, Sierra Club pre-filed the Direct Testimony of its witness:

Tyler Comings – Independent Contractor for synapse Energy Economics; testifying on the transfer of Pleasants with a focus on the Companies' capacity requirements and the economic analysis conducted by CRA.

On August 25, 2017, WVBIC pre-filed the Direct Testimony of its witness:

Chris Hamilton – Chairman, West Virginia Business & Industry Council; testifying about the importance to the State of preserving Pleasants.

On August 25, 2017, WVCA pre-filed the Direct Testimony of its witness:

William B. Raney – President, West Virginia Coal Association; testifying about coal production and Pleasants.

On August 25, 2017, WVEUG pre-filed the Direct Testimony of its witnesses:

1. Stephen J. Baron – President and a principal at J. Kennedy and Associates; testifying generally on the proposed Pleasants transfer, including the economics of the Transaction, the possible impact on the Companies' customers, the proposed ratemaking treatment, and the analysis by CRA.
2. Lane Kollen – Vice President and a principal at J. Kennedy and Associates; testifying on the accounting for the Pleasants transfer and the appropriate ratemaking for accumulated deferred income taxes if the Transaction is approved.
3. Michael K. Messer – Manager, Energy and Regulatory Affairs for Linde, LLC, and Chair of WVEUG; testifying from the perspective of a large industrial customer on the potential impact of the Pleasants Transaction on economic and operational decisions.

On August 25, 2017, WVSUN/CAG pre-filed the Direct Testimony of its witness:

David Schlissel – President, Schlissel Technical Consulting, Inc.; Analyzing all aspects of the proposed transfer Pleasants.

On September 18, 2017, the Companies pre-filed the Rebuttal Testimony of its witnesses:

1. Bradley D. Eberts – Responding to the direct testimony of witnesses Emily S. Medine, Steven Gabel, and Stephen J. Baron.
2. Dale Evans – Employed by FirstEnergy Service Company as the Technical Service Manager, Pleasants Power Station; responding to characterizations of the Pleasants plant as a deteriorating asset facing significant performance issues regarding investment and plant reliability, maintenance and operations and management costs, operating parameters, turbine efficiency and heat rate, boiler, and waste disposal and environmental costs.
3. Robert J. Lee – Responding to direct testimony of witnesses for Longview, WVSUN/CAG, the Sierra Club, and CAD regarding design and administration of the RFP and CRA's scoring of bids.
4. Kurt P. Leutheuser – Responding to claims by Mr. Kumar and Mr. Burnett that Pleasants is an inadequate generating asset.
5. Jay A. Ruberto – Addressing a variety of testimony from Intervenors including determination of capacity deficiency, value of a physical hedge, allegations of bias and undue advantage, NPV calculation criticisms, price criticisms, the value of Pleasants, customer benefit, and Pleasants' contribution to the State.
6. Thomas Sweet – Responding to the testimony of Mr. Schlissel, Ms. Medine, and Mr. Comings.
7. Raymond E. Valdes – Addressing the rate-related recommendations of witnesses Mr. Oxley, Mr. Short, Mr. Eads, Mr. Baron, Mr. Kollen, and Mr. Schlissel.

On September 18, 2017, Longview pre-filed Rebuttal Testimony of:

Steven Gabel – Addressing aspects of Staff and CAD witness direct testimony.

On September 18, 2017, WVEUG pre-filed Rebuttal Testimony of:

Stephen J. Baron – Responding to a variety of witnesses on the reasonableness of the Pleasants acquisition, its potential impact on ratepayers, and rate recovery issues.

**Evidentiary Hearing**

Between April 24, 2017, and May 5, 2017, the Companies published notice one time per week for two consecutive weeks in The Journal, The Exponent-Telegram, The Inter-Mountain, The Dominion Post, The Parkersburg News and Sentinel, The Times West Virginian, The Weirton Daily Times, The West Virginia Daily News, The Charleston Gazette Mail, and the News Tribune of the evidentiary hearing scheduled to begin on September 6, 2017. The hearing date was subsequently moved and the Commission published notice of the revised hearing date, September 26-28, 2017, in the Charleston Gazette Mail on May 5, 2017.

It was anticipated that the evidentiary hearing would conclude in three days; however, two extra days of hearing were necessary (September 29, 2017, and October 10, 2017). The Companies, Staff, CAD, WVEUG, WVSUN/CAG, Sierra Club, Longview Power, and HCP/BCP filed initial briefs on October 19, 2017, and reply briefs on October 26, 2017. WVBIC and WVCA did not file post-hearing briefs.

The Commission reviewed the 155-page Petition, including exhibits, pre-filed direct testimonies and exhibits consisting of approximately 1,376 pages of record evidence. The Commission also conducted three public comment hearings resulting in 250 pages of transcript of public testimony for and against the proposed sale, and an evidentiary hearing that resulted in five transcripts consisting of 1,211 pages and hundreds of pages of exhibits. The Commission also reviewed the initial and reply briefs filed by the Parties and consisting of approximately 400 pages of argument.